ENERGY USE
IN
ALUMINIUM INDUSTRY

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December 1986

Integrated Energy Pricing
Final Report

Submitted to the
Energy Management Centre, New Delhi

by the
Tata Energy Research Institute
9 Jor Bagh, New Delhi
March, 1992

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Acknowledgements

This study on integrated energy pricing has given us an opportunity to go into the details of several aspects of pricing of commercial energy sources. We are grateful to the Energy Management Centre, Department of Power, for sponsoring this useful study.

We are thankful to the officials from the state electricity boards, CEA, coal and oil companies as well as from several ministries and departments of the Government of India for the assistance provided in furnishing the primary data, which was extremely crucial to the study. In this respect, we would like to acknowledge the cooperation of Mr M K G Pillai and Mr M L Gupta from CEA, Mr S K Chand, Mr Sandeep Arora and Mr B C Niyogi from CIL, Mr Narasimhan, and Mr M N A Rao from CMPDIL (Ranchi), Dr A Bhattarcharyya and Mr R K Singhal (ONGC), officials from RITES and Mr N Dhanaraju (Indian Ports Association).

We also gratefully acknowledge the valuable insights and guidance provided by Mr P V Sridharan (TERI), Mr S K Chand (CIL), Ms Rita R Nangia (TERI) and Mr A N Banerjee at various stages of the project. We are also thankful to several experts in this area of energy pricing, particularly Dr Ramesh Bhatia, Dr Hiren Sarkar and Dr Gopal K Kadekodi, who gave their time for having discussions relating to the project. Dr E A S Sarma (Planning Commission) and Prof R P Sengupta also provided valuable suggestions for the study.

List of Abbreviations

APSEB	-	Andhra Pradesh State Electricity Board
ASEB	-	Assam State Electricity Board
ATF	-	Aviation Turbine Fuel
BCCL	-	Bharat Coking Coal Limited
bcm	-	billion cubic metres
BPCL	-	Bharat Petroleum Corporation Limited
BPRL	-	Bongaingaon Refinery and Petrochemical Limited
BSEB	-	Bihar State Electricity Board
CC	-	Coking Coal
CCL	-	Central Coalfields Limited
CCWO	-	Central Coal Washeries Organisation
CIL	-	Coal India Limited
CMAL	-	Coal Mines Authority Limited
CMPDIL	-	Central Mine Planning and Design Institute Limited
CNG	-	Compressed Natural Gas
COPE Account	-	Crude Oil Price Equilisation Account
CPI	-	Consumer Price Index
CRL	-	Cochin Refineries Limited
DVC	-	Damodar Valley Corporation
ECL	-	Eastern Coalfields Limited
EMS	-	Earnings per Manshift
EP	-	Economic Price
FO	-	Furnace Oil
GAIL	-	Gas Authority of India Limited
GEB	-	Gujarat Electricity Board
HPCL	-	Hindustan Petroleum Corporation Limited
HPSEB	-	Himachal Pradesh Electricity Board
HSD	-	High Speed Diesel
HSEB	-	Harayana State Electricity Board
HT	-	High Tension
IISCO	-	Indian Iron and Steel Company
IOBL	-	Indian Oil Blending Limited

List of Abbreviations

IOC	-	Indian Oil Corporation Limited
Kcal	-	Kilo calories
KEB	-	Karnataka Electricity Board
KSEB	-	Kerala State Electricity Board
KW	-	Kilo Watt
kWh	-	kilo Watt hours
LPG	-	Liquefied Petroleum Gas
LT	-	Low Tension
MCC	-	Medium Coking Coal
mcm	-	million cubic metres
MMSCMD	-	Million Standard Cubic Metres Per Day
MMSCMY	-	Million Standard Cubic Metres Per Year
MP	-	Market Price
MPEB	-	Madhya Pradesh Electricity Board
MRL	-	Madras Refineries Limited
MS	-	Motor Spirit
MSEB	-	Maharashtra State Electricity Board
mt	-	million tonnes
mty	-	million tonnes per year
NCC	-	Non-Coking Coal
NCDC	-	National Coal Development Corporation
NCL	-	Northern Coalfields Limited
NGL	-	Natural Gas Liquids
NTPC	-	National Thermal Power Corporation
OCC	-	Oil Coordination Committee
OCDL	-	Opencast Dragline with (shovel & dumper)
OCRC	-	Oil Cost Review Committee, 1984
OCSD	-	Opencast Shovel & Dumper
OIDB	-	Oil Industry Development Board
OIL	-	Oil India Limited
OMS	-	Output per Manshift
ONGC	-	Oil and Natural Gas Commission

List of Abbreviations

OPC	-	Oil Prices Committee, 1976
OSEB	-	Orissa State Electricity Board
O&M cost	-	Operating and maintenance cost
PCC	-	Prime Coking Coal
PSEB	-	Punjab State Electricity Board
REB	-	Regional Electricity Board
RSEB	-	Rajasthan State Electricity Board
SCCL	-	Singareni Colliery Company Limited
SEB	-	State Electricity Board
SECL	-	South-Eastern Coalfields Limited
SKO	-	Superior Kerosene Oil
TISCO	-	Tata Iron and Steel Company
TNEB	-	Tamil Nadu Electricity Board
UGBP	-	Underground Bord & Pillar
UGLW	-	Underground Long Wall
UHV	-	Useful Heat Value
UPSEB	-	Uttar Pradesh State Electricity Board
WBSEB	-	West Bengal State Electricity Board
WCL	-	Western Coalfields Limited
WPI	-	Wholesale Price Index

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Executive Summary

Energy demands have been growing very rapidly in the recent past leading to substantial shortages in the electricity and coal sectors and an increasing dependence on imports in the case of the oil sector. One of the major factors responsible for this rapidly increasing demand is the distorted pricing structure that exists in the country. Existing energy prices do not reflect the true cost of supplying energy to the consumers nor do they take into account the cross- price effects on demands for substitute fuels.

The present study attempts to develop an integrated energy pricing framework which would take into account not only the true cost of supplying energy to the consumer but would also incorporate possibilities for inter-fuel substitution as well as the need to meet the basic energy requirement of the population.

Mohan Munasinghe suggested a two stage method for the establishment of efficient prices. The first stage involves the estimation of marginal opportunity costs comprising the marginal supply costs and a depletion premium while the second stage requires the estimation of the demand side effects of a particular price structure. This study has estimated the marginal supply costs for electricity, coal and natural gas the marginal opportunity cost in the case of oil products which are tradeables at the margin.

An integrated energy pricing structure should meet the three objectives of pricing viz economic efficiency, social equity and financial viability. While the first objective has been explicitly taken into account, an assessment of the achievement of the other two objectives would necessarily have to take into account the price elasticities of demand for various categories of consumers. Since this is a major exercise in itself, we have merely developed a structure for doing so and propose to take up the estimation of the demand side effects as a subsequent exercise.

The steps required in developing this framework are summarized in figure 1.

A comparison of efficient prices, as estimated, with actual market prices is provided in Table 1 below.

Figure 1: Schematic representation of integrated energy pricing framework

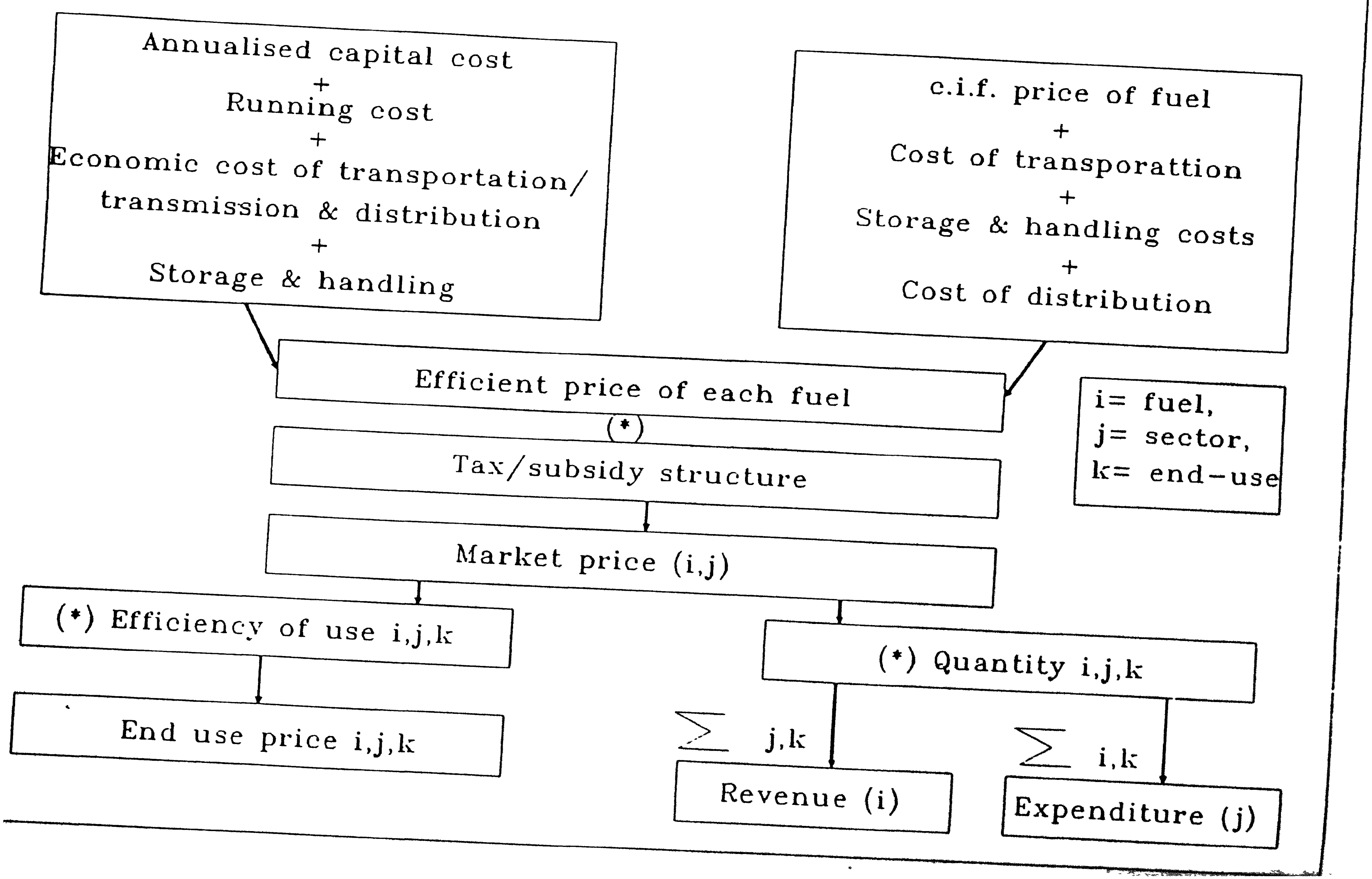


Table 1: Economic and market prices for a 750-1000 kms distance slab				
Fuel	EP	MP	EP Rs/10000	MP KCal
Coal (Rs/Tonne)				
NCC	369.36	574.80	0.82	1.28
PCC 0-250 kms	708.91	745.61	1.09	1.15
MCC 0-250 kms	414.18	716.43	0.69	1.19
SC	696.43	433.00	1.39	0.87
Oil(Rs/Tonne)				
FO	2257.59	3320.10	2.17	3.19
HSD	3630.33	4392.30	3.36	4.07
LPG	6430.98	3950.00	5.47	3.36
MS	4415.66	11116.32		3.96
SKO	4038.60	2788.45	3.67	2.53
Natural gas (Rs/'000 m^3)	1785.10	2250.00	2.04	2.57
CNG (Rs/'000 m^3)	3650.30		4.66	
Electricity(Rs/kWh)				
Domestic	0.98	0.47	11.40	5.47
HT Industry	0.64	1.10	7.44	12.79
LT Industry	0.87	0.75	10.12	8.72
Commercial	1.07	0.89	12.44	10.35
Agriculture	0.90	0.09	10.47	1.05
Note: EP - Economic price		MP - Market price		

A surprising result that emerges here is that the market price for coal is significantly higher (about 56%) than the economic price of coal. However, if one was to compare the economic and market prices at the pithead then the administered price of non-coking coal is Rs. 212 per tonne which is only about 10% higher than the economic price of Rs. 193 at the pithead in 1987-88. Obviously, the prevailing transport costs of coal are higher than the economic costs. A comparison of these costs reveals that the economic price of transportation over the distance slab 750-1000 kms is Rs. 0.20/TKM against the freight rate of

Rs.0.26/TKM charged by the railways. Additionally, the cesses that have been assumed at Rs. 88.50/tonne (for Bihar) are over 80% of the component of 'other levies'. Thus, the transportation sectors and the state governments benefit through coal transport and consumption.

Table 2 gives the summary of the results for the domestic sector arranged by end-use using both economic prices (EP) and market prices (MP). This table brings out starkly the very high levels of subsidy that are being offered to the domestic sector particularly in case of electricity and kerosene. LPG, which is considered as the rich man's fuel, is also very highly subsidized.

Table 2 : Domestic sector analysis

Fuel	Price(Rs/tonne or kWh or '000m3)		Price (Rs/10000 kcals)		Efficiency matrix		End use prices			
	EP	MP	EP	MP	Lighting (Kcals/ lhr)	Cooking & W.heating (U Kcals/Kcal)	EP	MP	EP	MP
							Lighting (Rs./lhr)		Cooking & W. Heating (Rs./10000 kcals)	
Soft coke	696.43	433.00	1.39	0.87		0.25	0.00	0.00	5.57	3.46
SKO	4038.60	2788.45	3.67	2.53	2.88	0.45	1.06	0.73	8.16	5.63
LPG	6430.98	3950.00	5.47	3.36		0.65	0.00	0.00	8.42	5.17
Electricity#	0.98	0.47	11.40	5.47	0.17	0.64	0.20	0.09	17.81	8.54
Electricity*	0.98	0.47	11.40	5.47	0.03	0.64	0.04	0.02	17.81	8.54

Note: lhr - lumen hours
U Kcals - Useful Kilocalories
#: Electricity use in incandescents
*: Electricity use in fluorescents

Table 3 gives a comparison of energy prices per unit of useful output using alternative fuels for the industrial end-uses of process heating and lighting. It is seen that all the three fuels viz. fuel oil, coal and natural gas used in this sector are taxed products, whereas the use of electricity is subsidized to the commercial and LT sectors although not to the same extent as in the domestic sector.

Table 3 : Industrial and commercial sector analysis										
Fuel	Price (Rs/tonne or kWh or '000 m3)		Price (Rs/10000 kcals)		Efficiency matrix		End use prices			
					Process heating (Ukcals/kcal)	Lighting (kcals/lhr)	Process heating (Rs/1000 kcal)		Lighting (Rs/'000 lhr)	
	EP	MP	EP	MP			EP	MP	EP	MP
Non coking coal	369.36	574.80	0.82	1.28	0.55		1.49	2.32		
Coking coal	561.55	731.02	0.89	1.17						
Fuel oil	2257.59	3320.00	2.17	3.19	0.75		2.89	4.26		
Natural gas	1785.1	2250	2.04	2.57	0.80		2.55	3.22		
LPG	6430.98	3950.00	5.47	3.36						
Electricity-com#	1.07	0.89	12.44	10.35		0.17			0.21	0.18
Electricity-com*	1.07	0.89	12.44	10.35		0.03			0.04	0.04
Electricity-LT#	0.87	0.75	10.12	8.72		0.17			0.17	0.15
Electricity-LT*	0.87	0.75	10.12	8.72		0.03			0.03	0.03
Electricity-HT#	0.64	1.10	7.44	12.79		0.17			0.13	0.22
Electricity-HT*	0.64	1.10	7.44	12.79		0.03			0.03	0.04
#: Electricity use in incandescents *: Electricity use in fluorescents										

The consumption of non-coking coal, petrol and diesel are taxed in the transportation sector. There also exists a substantial tax on the use of electricity for traction purposes.

Table 4: Transport sector analysis										
Fuel	Price (Rs/Tonne or kWh or '000 m^3)		Price (Rs/10000 Kcal)		Efficiency matrix		End use prices			
	EP	MP	EP	MP	Freight (Kcals/TKM)	Passenger (Kcals/PKM)	EP	MP	EP	MP
							Rs./'000 TKMS		Rs./'000 PKMS	
Non coking coal	369.36	574.80	0.82	1.28	852.6	294.00	69.98	108.91	24.13	37.55
Motor spirit	4415 66	11116.33	3.96	9.97		348.6			138.05	347.55
HSD-Rail	3630.33	4392.30	3.36	4.07	63.18	41.58	21.24	25.69	13.98	16.91
HSD-Road	3630.33	4392 30	3.36	4.07	449.59	52.5	152.05	182.84	17.65	21.35
Electricity-Rail	0.64	1.10	7.44	12.79	18.92	15.82	14.08	24.20	13.98	20.23
CNG-bus/HCV	3650.3		4.66		197.98	23.38	92.18		10.89	
CNG-car/HCV	3650.3		4.66			250.22			116.50	

A comparison is presented in Table 5 between electric and diesel pumpsets. Again while diesel is a taxed product, the subsidy provided to the agricultural sector on electricity consumption is extremely high. As against the economic price of 91.90 rupees per thousand m^3 of water pumped, the market price charges to this sector is a mere 9.2 rupees per thousand m^3.

Table 5 : Agricultural sector analysis

Fuel	Price		Price			End use price	
	EP	MP	EP	MP	efficiency	EP	MP
	Rs/tonne (or kWh)		Rs/10000 Kcal		Kcals/M3	Rs./'000 m3	
HSD	3630.33	4392.30	3.36	4.07	349.65	117.53	142.20
Electricity	0.90	0.09	10.47	1.05	87.80	91.88	9.19

As per our estimation, the energy sectors are revenue generating contributing nearly Rs.5000 crores in 1987-88: domestic sector - (-)2104 crores; transport sector - (+)4490 crores; industrial sector - (+)5323 crores; and agriculture - (-)2702 crores.

CHAPTER 1
OBJECTIVES AND SCOPE OF THE STUDY

1.1 Background

Energy availability has been and continues to be a constraint to the development of the Indian economy while energy demands have placed a severe stress on the financial and foreign exchange resources of the country. As is brought out in Table 1.1. Energy consumption, which has been growing rapidly since the 1960s, has accelerated in the 1980s. Thus, the rate of growth of coal consumption in the period 1980-81 to 1988-89 was about 12.6% whereas that of oil products was as high as 9.2%. Electricity consumption, although lower than the 1950s and 60s, still registered a growth rate of 9%. While a part of this increased growth rate in consumption can be ascribed to the fact that the economy itself registered an all time high growth of 5.6% in the 1980s, the energy consumption intensities of various sectors also increased fairly rapidly.

Table 1.1 : Energy consumption in India

Source	Unit	1960-61	1970-71	1980-81	1988-89
Coal	MMT	40.4 (5.0)	51.5 (2.4)	71.1 (3.3)	187.4 (12.6)
POL	MMT	6.7 (8.9)	15.0 (8.4)	24.6 (5.1)	49.8 (9.2)
Power	TWH	16.9 (12.1)	48.7 (11.1)	89.7 (6.3)	78.5 (9.0)
GDP(1)	Rs.10^7	62904 (4.0)	90426 (3.7)	122226 (3.1)	188981 (5.6)

Figures in brackets present annual compound growth rates between the period e.g. 1953-54 to 1960-61 and so on.
Source : WGEP (1979) and Economic Survey, various issues.
(1) At 1980-81 Constant Prices

As a result of this rapid increase in the demand for energy, the financial requirements of the energy sector have also increased substantially in order to enhance the supply of various energy forms. Thus, while the energy sector accounted for about 14.6% of plan outlays in the 3rd plan, this increased to 18.6% in the 4th plan, 18.8% in the 5th plan, 28.1% in the 6th plan and finally to over 30% in the 7th five year plan making it the single largest beneficiary of total public sector outlays.

Despite this increase in the level of investment in the energy sector, energy supply has not kept pace with the growth in energy demand and there are increasing shortages in the energy sector. In the case of electricity, these shortages are in the range of 8 to 10% (Table 1.2).

Table 1.2: Power shortages in recent years

Region	1984/85	1985/86	1986/87	1987/88	1988/89
Requirement	155432	170746	192356	210993	202711
Availability	145013	157262	174276	187976	187038
Surplus (+)/ Deficit (-)	(-)10419	(-)13484	(-)18080	(-)23017	(-)15673
Surplus(+)/ Deficit (-)	(-)6.7	(-)7.9	(-)9.4	(-)10.9	(-)7.7

Source : TEDDY 1989

In the petroleum sector, the level of crude oil and petroleum product imports is an indicator of the shortages felt in this sector. While India's oil import dependence in the early 1970s was extremely high, in the range of 70 to 80%, this dependence declined following the discovery of oil in the Bombay High region in 1975. Subsequently, there was a steady decline in the dependence on oil imports which lasted up to the mid 1980s. However, the rapid increase in demand for petroleum products in the 1980s coupled with a levelling, if not an actual decline, in the production from Bombay High has resulted in increasing the share of petroleum imports in total consumption once again. Thus, in addition to placing a severe financial constraint on the Indian economy, the demands on the energy sector are also having a severe adverse impact on the balance of payments position of the country.

While several factors have contributed to this growth in energy demand, one of the major contributors has often been said to be the distorted energy pricing structure that exists in the country. Prices, as they are currently set, do not in any way reflect the true cost of supplying energy to the consumers nor do they take into account the impacts of a particular price structure in one of the energy sub-sectors on other energy sub-sectors. For example, the highly subsidized price of electricity in rural areas has discouraged the use of otherwise economically efficient renewable energy technologies while the subsidy on kerosene has often resulted in its misuse in the transport sector. Several exercises that have projected future energy demands point to the unsustainability of this growth in energy consumption. There is, thus, an urgent need to resort to stringent demand management measures.

Pricing is one of the policy instruments available for optimal supply-demand management and planning. While several other tools are also available, it has been generally found that pricing is the most effective tool for demand management, particularly in the long run.

1.2 Objectives of the present study

It is proposed to develop an integrated energy pricing framework which would take into account not only the true cost of supplying energy to its consumers but would also incorporate possibilities of inter-fuel substitution as well as the need to meet the basic energy requirements of the population.

1.3 Scope of the study

Almost all the literature on energy pricing points towards three main goals of pricing which are:

(1) economic efficiency
(2) social equity, and
(3) financial viability

The economic efficiency objective would subserve the promotion of economically efficient allocation of resources both within the energy sector and between it and the rest of the economy. This would reflect the incremental resource cost of supply to the national economy. The social objective recognizes the basic right of all citizens to be supplied with certain minimum energy needs. While the financial objective would ensure the viability and autonomy of the energy sector it would also take into account the general revenue goals of the government. In this study, we would be stressing all the three objectives of a pricing policy to varying degrees.

The process of establishing an efficient economic price has been analysed in two steps by Munasinghe. First is the determination of the marginal opportunity cost (MOC) of supply and secondly, an adjustment to compensate for demand side effects. The MOC consists of marginal costs of extraction and transport which could be referred to as the marginal supply cost (MSC) plus an appropriate discounted user cost or foregone surplus benefits of future consumption. The latter component of the MOC defined above is a reflection of scarcity value of depletable energy sources. In this study, we have restricted ourselves to the estimation of MSC owing to the paucity of data and resources. For tradeable items like oil the international or border prices are accepted as appropriate indicators of MOC, whereas for non-tradeable items one would have to estimate the MSCs. The following chapters give details of the methodologies adopted for estimating MSCs of petroleum products, coal and electricity.

Social objectives of energy pricing are dealt with in a relatively superficial manner largely because of the difficulties associated with defining demand curves for various groups of consumers. Ideally, one would have to estimate price elasticities of energy demand for various sections of the population and to study the impact of alternative tax/subsidy structures on the demands for various fuel types and on the resultant expenditure levels of this section of population. However, this is a major exercise in itself and we hope to attempt it as a sequel to this project. Here, we attempt an analysis of the relative cost of substitute fuels in meeting specific end-use energy requirements. Similarly, the financial objectives have also been dealt with in a partial manner again primarily because of the lack of information on elasticities of demand.

1.4 Format of the pricing report

Chapter 2 provides an overview of the organizational structure of the energy sector and some useful background information. Chapter 3 presents, in brief, the steps involved in the development of an integrated energy pricing structure for India. Chapter 4 deals with the setting of energy prices historically while chapter 5 details the methodology that has been adopted for estimating the marginal supply cost of petroleum products, coal, electricity and natural gas. It also provides the summary of the efficient set of prices for these fuels. In chapter 6, are incorporated some social and financial considerations into the efficient price structure developed in chapter 5. Finally, chapter 7 highlights some of the main results from the entire exercise and provides the conclusions.

CHAPTER 2

ORGANIZATIONAL STRUCTURE OF THE ENERGY SECTOR

2.1 Organizational developments in the energy sector

The energy supply industry in India lies almost entirely in the public sector, the main exception being a small segment of the power supply industry. At the time of the first oil shock, in early 1970s the responsibility for energy was distributed among separate departments for coal, petroleum, electricity and nuclear power. In 1982, as per the recommendations of the Working Group on Energy Policy (1979), a Ministry of Energy was created consisting of the Departments of Power, Coal and Petroleum, and a new Department of Non-Conventional Energy Sources (DNES) was established.

This structure was dismantled at the end of 1984. The Department of Power was merged with the Department of Irrigation to become the Ministry of Irrigation and Power. The Department of Coal became a part of the Ministry of Steel, Mines and Coal. The Department of Petroleum became a Ministry in its own right and the DNES was made part of the Ministry of Science and Technology. These ministries were again restructured in September 1985, when a new Ministry of Energy was created. A separate Ministry of Petroleum and Natural Gas was created in January 1986. This sequence of changes demonstrates the difficulty of identifying the most effective structure for policy decision making.

2.2 Petroleum and natural gas subsector

The petroleum industry in India is almost completely in the hands of the public sector. The scope of activities in this sector includes exploration, storage, transportation, marketing and distribution, research and development etc. Until 1950s the Indian oil scene was largely dominated by multi-national companies and a major part of the crude oil and petroleum products were being imported into the country from West Asia.

Visualizing that domestic production of crude was gradually becoming important, the Oil and Natural Gas Commission (ONGC) was created in 1959 as a statutory body under the Oil and Natural Gas Act, 1959. Further, a number of other companies were registered under the Companies Act, 1956 to cover the entire gamut of activities relating to the petroleum sector in India.

The following table enlists some of the major organisations associated with the petroleum sector and their main activities.

Table 2.2.1 : Major organisations associated with petroleum sector	
Activity(s)	Name of the Organization
Exploration and production of crude oil and natural gas, transportation thereof	ONGC,.OIL
Refining of crude oil	IOC,BPCL,HPCL,MRL, CRL, BPRL
Marketing of petroleum products	IOC, BPCL, HPCL
Import and export of crude oil and petroleum products	IOC
Blending of lubes and greases	IOC, BPCL, HPCL, IOBL, IBP
Manufacture of petroleum products	BRPL
Manufacture of plant and machinery	IBP
Assistance to oil industry and levy of excise on crude oil and natural gas	OIDB
Coordinating the activities of oil industry viz, planning of facilities, imports, exports, distribution of crude to refineries, pricing of petroleum products, short term estimates of demand and supply and import plans.	OCC

2.3 Coal sub-sector

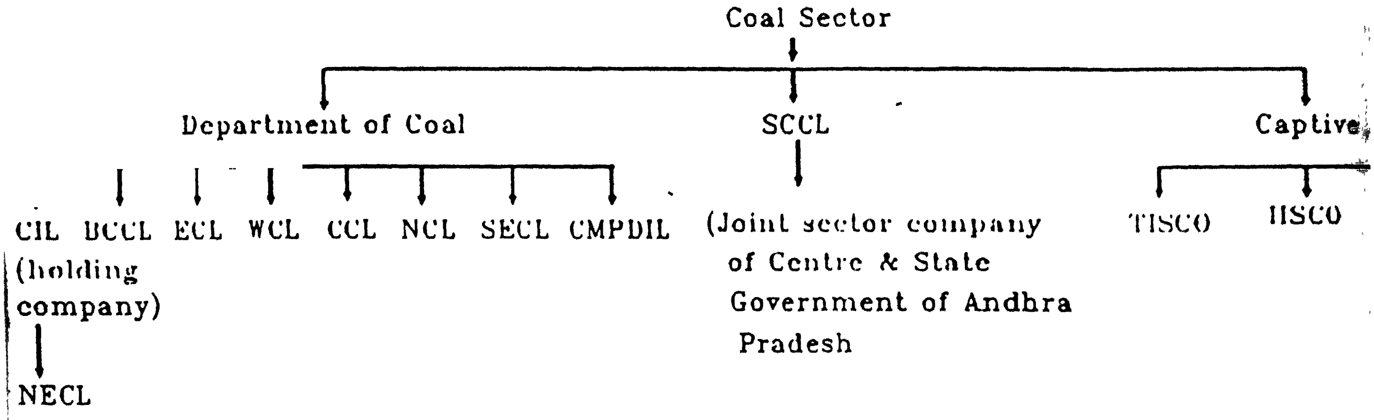
Coal mining in India has a long history, essentially in the hands of private miners. The entry of public sector in the coal industry dates back to 1920s when railways, along with their captive mines, were taken over by the government in a phased manner. Over thirty years later, in 1956, with the formation of the National Coal Development Corporation (NCDC) these Railway Collieries were taken over by this corporation. Thereafter in 1959 the Singareni Colliery Company Limited (SCCL), a privately held Nizam State Enterprise, was made a joint sector company of the Central Government and State Government of Andhra Pradesh.

Upon nationalisation in May 1972, the control of all coking coal mines was vested with Bharat Coking Coal Limited (BCCL). In May 1973, the entire coal industry was nationalised, following the take over of non-coking coal mines (except in the N-E region), and vested with the Coal Mines Authority Limited (CMAL) and NCDC was made its subsidiary.

In November 1975, the management of these central public sector coal companies was re-organised. A new holding company, i.e. Coal India Limited (CIL) was incorporated, with five subsidiary companies viz. Bharat Coking Coal Limited (BCCL), Eastern Coalfields Limited (ECL), Central Coalfields Limited (CCL), Western Coalfields Limited (WCL) and Central Mine Planning and Design Institute Limited (CMPDIL). Mines

of North-Eastern Coalfields Limited (NECL) were placed under direct control of CIL. SCCL continued to be a separate entity. Further, captive mines of TISCO, IISCO and DVC persisted to be under their respective organisations. In 1985-86 some reorganisation was done whereby two new coalfields viz. Northern Coalfields Limited (NCL) and South Eastern Coalfields Limited (SECL) were created, again as subsidiaries of CIL. Until then NCL was included under CCL while SECL was included under CCL and WCL. This new organisational structure of coal sector, as sketched out in Figure 2.3.1 below, has continued since then.

Figure 2.3.1 : Organisational structure of coal industry in India



2.4 Organisational structure of the power sector

In the 1940's, the electric utility industry in India was mainly in the private sector. There were numerous private undertakings, the bulk of them concentrated in the urban areas, each having its own independent system to supply power in its area of jurisdiction. There was little coordination or cooperation among them as their areas of activities were isolated and often located far apart. At the time of independence, in view of the importance of power in economic development, the government decided to nationalise and restructure the entire power industry. It was in this context that a separate comprehensive legislation, outside the purview of the 1910 Act, was conceived at the time of independence to provide the electricity supply industry with an organisational structure for the state-owned sector.

As a result of the Electricity (Supply) Act 1948, State Electricity Boards (SEBs) were created in each state, and were charged with the responsibility of promoting coordinated development in an efficient and economic manner. By late 1950's, SEBs were established in all the states. In Union Ter ories, electricity departments were set up and local governments were made responsible for power development. In Manipur, Nagaland, Sikkim and Tripura electricity supply became the responsibility of departmental organisations. In several states, licensees already engaged in generation and distribution of power supply were allowed to continue in business so long as their licenses were valid. There are still a few private licensees continuing although most of the licensees have been nationalised. Today, there are three utilities in the private sector engaged in power generation and sales viz. Tata Electric Company, Calcutta Electric Supply Corporation (India) Ltd. and Ahmedabad Electricity Company Ltd., supplying licensed areas in Bombay, Calcutta and Ahmedabad respectively.

The need to supplement the efforts of the states was felt in the early seventies, when power shortages were felt in several states. In 1976, the Electricity (Supply) Act was amended to provide for the establishment of generation companies by central and the state governments. Two central generation companies - National Thermal Power Corporation and National Hydro-Electric Power Corporation and one centrally owned regional generation company - Northern-Eastern Electric Power Corporation have been established so far. These companies sell power to the SEBs.

Table 2.4.1 and 2.4.2 give ownership-wise details of installed capacity and energy sold respectively. The share of SEBs and Electricity Departments in total installed capacity increased from 68.2 % in 1960-61 to 88.6 % in 1971-72 and further to 95 % in 1986-87. On the other hand the share of private companies in the total installed capacity declined significantly from 30 % in 1960-61 to 4.2 % in 1986-87. The proportion of electricity sold by SEBs and Electricity Departments has increased from 74 % in 1971-72 to 86.4 % in 1986- 87. The %age of energy sales by municipalities and the private sector declined from 5.5 % and 20.5 % respectively in 1971-72 to 4.8 % and 8.8 % respectively in 1986-87.

Table 2.4.1 : Ownership-wise installed capacity of power (MW)

Year	SEBs	Electricity departments*	Munici-palities	Private companies	Total
1960-61	2604.6 (56.8)	524.0 (11.4)	94.8 (2.1)	0355.6 (29.6)	4579 (100)
1971-72	10005.0 (65.6)	3507.0 (23.0)	2570.0 (1.7)	1485.0 (9.7)	15254 (100)
1975-76	13913.2 (69.2)	4600.0 (22.8)	301.2 (1.5)	1302.2 (6.5)	20116 (100)
1980-81	23455.7 (77.6)	5100.5 (16.9)	275.8 (0.9)	1381.7 (4.6)	30214 (100)
1986-87	34672.3 (70.5)	12086.8 (24.5)	416.6 (0.8)	2090.2 (4.2)	49266 (100)

Figures in brackets are in %.
* Includes Government Undertakings/Corporation/Central Government Sectors
Source: [8]

Table 2.4.2 : Ownership-wise electricity sales (MUs)

Year	SEBs	Electricity departments	Munici-palities	Private companies	Total
1971-72	31277 (66.5)	3536 (7 5)	2583 (5.5)	9657 (20.5)	47053 (100)
1975-76	43656 (72.5)	4180 (6.4)	3024 (5.0)	9385 (15.6)	60245 (100)
1980-81	64662 (78.5)	4095 (5.0)	4226 (5.1)	9383 (11.4)	82366 (100)
1986-87	111365 (81.9)	6150 (4.5)	6495 (4.8)	11942 (8.8)	135952 (100)

Figures in brackets are in %.
Note : Energy generation by Central Sector Corporation is included in the sales of electricity by SEBs.
Source: [8]

The country has been divided into five regions for integrating the power system in each region. Each region comprises three to four states. Regional Electricity Boards (REBs) are set up with the objective of coordinating the operations of power supply industry in the five regions. REBs coordinate SEBs generation schedules and maintenance programmes, monitor systems operations and help arrange inter-state power exchanges.

The Central Electricity Authority (CEA), established as a part-time body in 1951 and formalized into a full-time body in 1974, coordinates the activities of the power sector in the country. CEA's objectives are to develop national power policy and coordinate sectoral development. It is responsible for promoting the integration of the state's power systems and for providing technical support to the SEBs.

CHAPTER 3

FRAMEWORK FOR INTEGRATED ENERGY PRICING STRUCTURE IN INDIA

The steps involved in the formulation of a framework for Integrated Energy Pricing in India are detailed below. Steps 1 to 4 deal with the construction of efficient prices.

Step 1: Cost of production/import: Establishment of economically efficient prices involves the use of real rather than the financial cost of resources. Here, a distinction is generally made between the tradeable and non-tradeable fuels. In case of tradeable products, the efficient price is worked out on the basis of their border price suitably adjusted for the shadow price of foreign exchange (to reflect foreign exchange scarcity premium). In case of importables, the shadow price is its c.i.f. price inclusive of a premium on the foreign exchange outflow while for exportables the efficient price is its f.o.b. price. The efficient price of non-tradeable fuels is determined on the basis of their real resource cost of production viz. capital outlay, working capital, salaries and wages and other operating expenditure.

Step 2: The cost of processing/beneficiation of primary fuel: The cost of processing of primary fuels viz. refining of crude oil, washing of coal, manufacture of soft coke etc. is added to the cost of production. The cost components here are similar to those included in the calculation of production costs of non-tradeable fuels.

Step 3: Cost of transportation: The economic cost of transportation is built in by adjusting it to reflect real resource cost of transporting and handling the fuel by different modes viz. rail, road, sea, pipeline, etc. This is added to the cost of the processed fuel to arrive at its delivered price. Since cost of transportation constitutes a major component of delivered price, the cost of supplying energy to its consumers is computed for different distance slabs.

Step 4: Other costs: These costs refer to the costs of marketing and distribution by intermediaries, viz. wholesalers and retailers who collect the product from the manufacturer and supply it to consumers. These primarily consist of costs of storage, intra-city transportation, infrastructure and running expenses.

Step 5: Modified price: The efficient delivered price, hence obtained, is modified to incorporate taxes and subsidies so as to take care of the financial, revenue generation and social welfare objectives. This would form the market price.

Step 6: Integrating prices in a single framework: An efficiency matrix is constructed consisting of efficiencies of fuel consumption is specific end-uses measured in terms of energy consumption per unit of useful output. The product of this matrix with the fuel price matrix gives the price per unit of useful output for each end-use using alternative fuels. Two fuel price matrices are taken into account - one based on economic prices and the other on market prices.

CHAPTER 4

4.1 Prevailing petroleum pricing in India

4.1.1 Historical evolution of petroleum pricing

History of administered petroleum prices

Regulation of petroleum pricing dates back to the mid twentieth century. The very first attempts to administer the oil prices were based on procedures negotiated between the Government of India and Burma Shell in 1950. Subsequently, the Chief Accounts Officer analysed the structure of petroleum prices and a new ad hoc arrangement was adopted with effect from 1st April 1959. Thereafter, it was in 1961 that earliest attempts were made to systematically regulate the prices of petroleum products. These were based on the recommendations of Damle Committee (1961) which marked the beginning of a series of committees to be set up by the government from time to time.

Since, at that juncture, bulk of crude oil and petroleum products were being imported into the country from West Asia, Damle Committee (1961) and Talukdar Committee (1965) recommended the 'import parity' principle for fixing petroleum product prices.

The Shantilal Shah Committee (1969), however, suggested a change away from the import parity concept because indigenous supply of crude oil was gradually becoming important by that time. Nevertheless, the import parity had to continue because of the commitments made to the international oil companies under the 'refinery agreements' under which they had built refining facilities in India.

In 1969, the Shantilal Shah Committee adopted the posted prices of petroleum products in West Asia and a predetermined per centage rise or fall in domestic prices linked to changes in the prices in West Asia. The Committee also made provisions for marketing margins and profits for each product on a normative basis.

The principle of import parity persisted till 1976 when the Oil Prices Committee (1976) recommended its discontinuance owing to a number of reasons. Firstly, the import of products constituted less than 10 per cent of total demand and any future increases in demand were to be met by domestic production and refining of oil. Secondly, the posted prices of petroleum products from West Asia were not representative of the scale of operation and hence not representative of refining conditions in India. Thirdly, these

reasonable return on the capital employed. A similar concept was extended to cover marketing and distribution activities also. This principle has persisted since then.

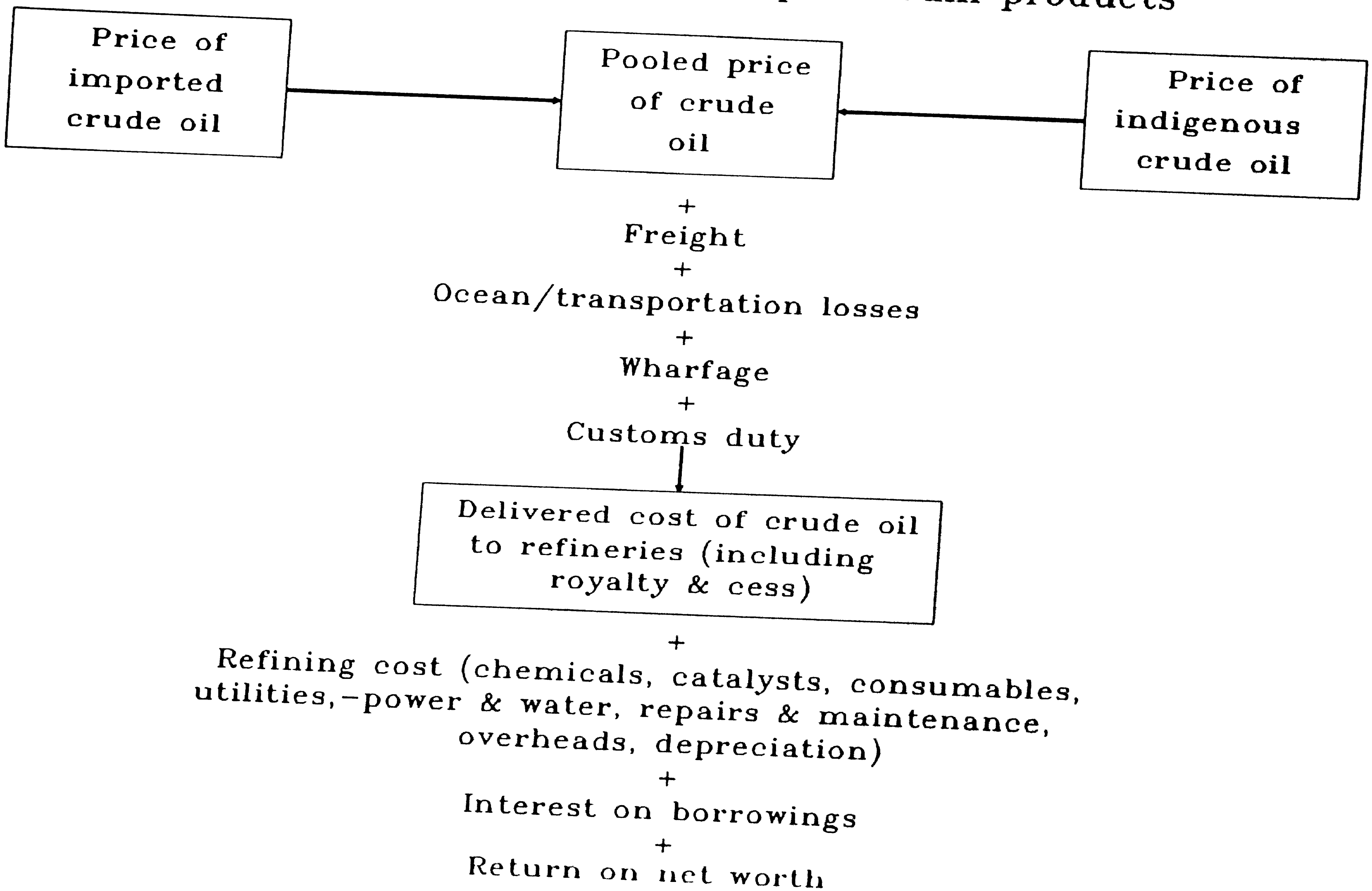
Current Petroleum Pricing Policy

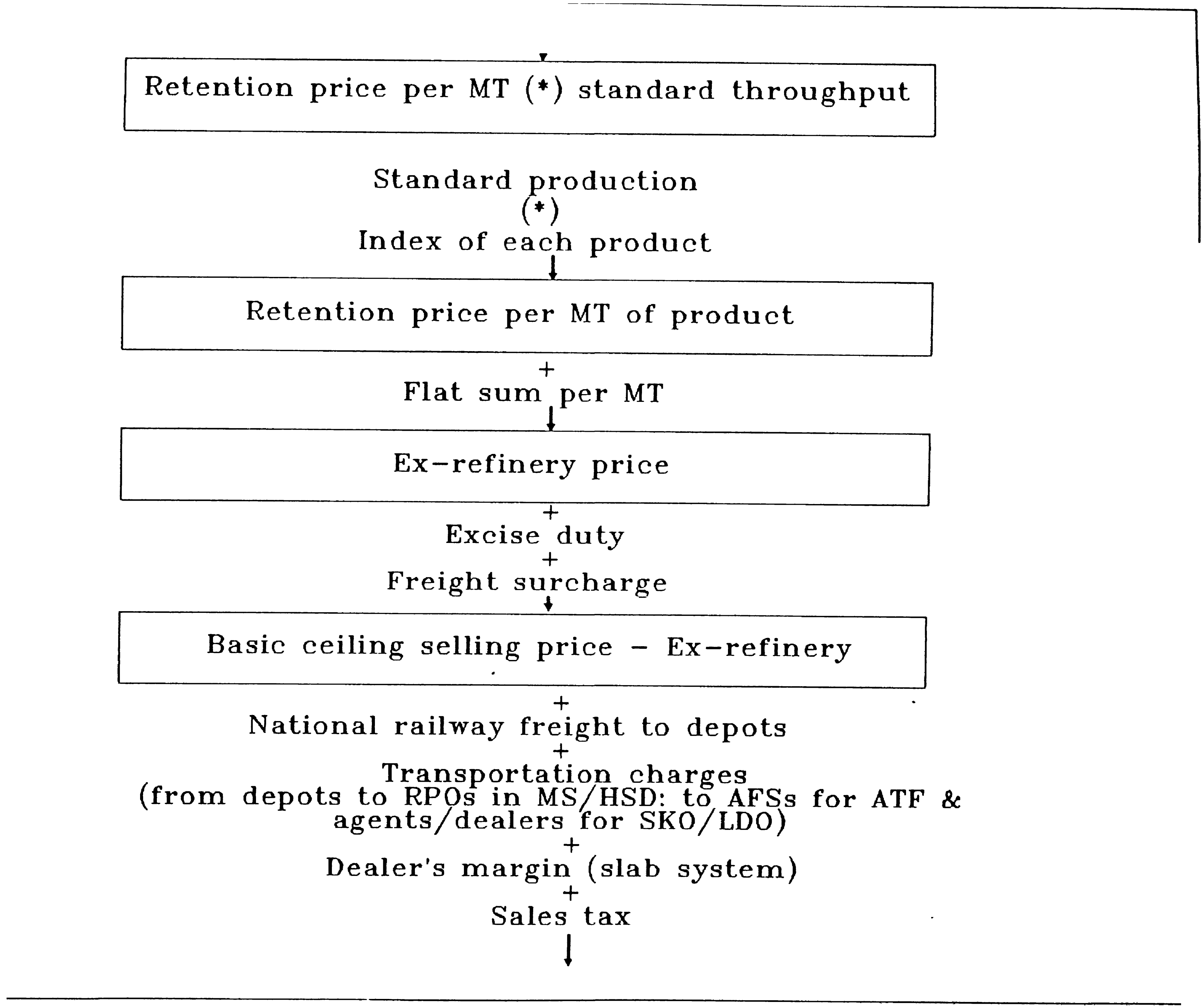
Petroleum prices are fixed by the government and revised from time to time, for various stages of the supply industry. Pricing of petroleum products is based on the concept of 'retention pricing', taking into account the delivered cost of crude oil, its refining costs and some reasonable rate of return on the capital employed. The 'retention concept' is extended to cover distribution and marketing activities also.

Presently, the oil refining and marketing organisations are compensated as suggested by the OPC, 1976 and subsequently updated by OCC and accepted by the Government. These prices are administered through a series of pool accounts. The price of the resource i.e. crude oil,to be paid to the petroleum exploration and production organisations is decided on the basis of their cost of operation and a reasonable margin for expanding future exploration and production activities. The second stage involves 'transfer pricing' i.e. price paid for crude oil by refineries to the producers. This is determined by means of pooling the prices of indigenous and imported crude oil and relates essentially to sharing of 'economic rent' arising due to the use of an exhaustible resource between producing and refining organizations. The third stage pertains to 'output/product pricing' whereby the retention prices for refineries are set keeping in mind the product mix to be attained with respect to their demand, while ensuring the financial viability of the refining companies. A similar concept is adopted for fixing retention prices for organizations engaged in distributing and marketing these products to 'consumer pricing'. The consumer price are fixed on the basis of certain social considerations.

A detailed price build-up of petroleum products is presented in Figure 4.1.1 below.

Figure 4.1.1 : Price build-up of petroleum products




Retention price per MT (*) standard throughput
Standard production
(*)
Index of each product
Retention price per MT of product
+
Flat sum per MT
Ex-refinery price
+
Excise duty
+
Freight surcharge
Basic ceiling selling price - Ex-refinery
+
National railway freight to depots
+
Transportation charges
(from depots to RPOs in MS/HSD: to AFSs for ATF & agents/dealers for SKO/LDO)
+
Dealer's margin (slab system)
+
Sales tax

+

Octroi tax & local levies

Consumer price

↓

Differential pricing

4.1.2 Prevailing methodology for petroleum pricing

The methodology adopted for pricing petroleum, at each stage of processing, is discussed in the following paragraphs.

A. <u>Crude oil price</u>

The price of indigenous crude oil (both from onshore and offshore areas) has been fixed at Rs 2113 per ton for 34° API (American Petroleum Institute) Gravity crude with effect from 1 2.1984. The price build-up is as follows :

	Rs/tonne
Basic price	1021
Royalty	192
Cess	900
	2113

The base price paid to crude producers is Rs 1021 per tonne. IOC is the canalising agent for imported crude oil in the country. The average price of imported crude is Rs 2046 per ton in the period April to December 1989.

B. Pooled price of crude oil

The price charged for crude from the refineries is determined by pooling the price of indigenous and imported crude oil. An account called the Crude Oil Price Equalisation (COPE) account was introduced, to which the processors of indigenous crude oil pay the difference between the pooled price of crude oil and indigenous price of crude oil, while the processors of imported crude oil claim the differential between approved price of crude oil and the pooled price of crude oil. The two transactions i.e. injections and withdrawals in the COPE account are expected to balance each other so that a uniform price is paid by different refineries.

C. Cost of crude oil at refineries :

The cost of crude oil at refineries is the sum of the pooled price, transportation costs incurred in bringing the crude oil to the refineries by tankers or pipelines, losses involved in transportation and handling, insurance paid to the marine companies, wharfage charges payable to port authorities and auxiliary duty payable to the government (including royalty and cess payments). The basis for determining the individual components is discussed below:

1. Ocean/Inland freight : Crude oil is transported for refining by tankers and/or by pipelines. The cost of carrying by tankers is worked out on the basis of the rates under the contract committee and Shipping Corporation of India/other Indian shipping companies. Under these agreements, the cost of transportation is estimated on cost plus profit basis. In case of transportation by pipelines, the compensation is based on actual costs and certain norms of operation. The actual annual cost of operation comprises wages and salaries, repair and maintenance and depreciation including a certain rate of return on net worth. In order to encourage efficiency in utilisation of facilities, a certain norm of capacity utilisation is adopted for determining the transportation rate.

2. Ocean/Inland losses : Ocean loss refers to the difference between the quantity loaded in the tankers at loading ports and the quantity as received at the port of destination. The OPC, 1976 & OCRC, 1984 have laid down a norm of 0.5% for ocean loss for imported crude oil. To improve the performance in this respect, any loss exceeding the ceiling is not debitable to the oil industry pool account. At the same time, any benefit accruing from a reduction in these losses will be credited to refineries as an incentive for an effective control of losses.

On Bombay High crude carried to Gujarat and Mathura refineries by means of pipelines owned and operated by IOC, a loss of 0.25% is allowed as storage and pipeline loss. In case of pipelines owned and operated by OIL & ONGC, no element of loss is allowed.

3. Insurance, wharfage, customs duty : Under normal conditions, the rate of marine insurance for imported crude oil is allowed at the rate of 0.12% of its cost and freight. However, in case of disturbed conditions, insurance companies may charge an extra premium over and above the normal premium. The wharfage rates applicable to both imported and Bombay High crude oils are the actual rates charged at individual ports. Furthermore, the prevalent rates of customs duty on imported crude oil is included in the delivered cost of crude to the refineries.

D. Cost of refining : For calculating the retention prices for different products, OPC, 1976 (and presently OCC, Technical Wing) have fixed standard thruput and product patterns for individual refineries, taking into account - availability of crude oil, secondary processing facilities, normative fuel and loss percentages and other technical factors. For refineries, the compensation for its costs and return on the investment is decided on the basis of their level of standard throughput and product mix thereof.

The cost of refining essentially consists of the following elements.

1. Raw material cost : This is the delivered cost of crude oil to various refineries as discussed above.

2. Refinery cost : This includes expenditure on chemicals, catalysts, consumables, utilities (power and water), salaries & wages, repair and maintenance, overheads and depreciation of fixed assets. These are fixed by OCC/Government on the basis of actuals with suitable provision made for periodic revisions on the basis of past trends and projections given by the refining companies for future escalation in different cost components such as escalation in the rate of major chemicals, increase in labour costs under long term contractual agreements, increase in power/water tariffs etc.

3. Return on investment : As a margin for different companies, a reasonable rate of return is allowed on net worth basis. For this purpose the total capital employed is worked out after taking into account the net fixed asset and working capital.

E. Prices of petroleum products - ex-refinery: On the basis of refining costs, the ex-refinery price of different petroleum products is determined in two steps :

1. Determination of retention prices : For allocating the total refinery cost to individual products, the OPC 1976 had evolved a set of indices whereby kerosene, a product of mass consumption, was used as the base and other products were related to it. These have been subsequently revised by OCRC, 1984 in consultation with the technical wing of OCC, by taking into account the prevailing demand and supply position in the country, ability of products to bear additional charges, their end-use profiles, international prices of various petroleum products and the need to favour production of certain products with a view to conserve foreign exchange. Broadly, these indices are a reflection of national requirements.

2. Determination of ex-refinery prices : Productwise uniform ex-refinery prices are derived based on the weighted average retention prices of each of the products of all refineries in India. These are converted from weights to volume by adopting conversion factors. To this, a certain flat sum is added to avoid frequent revisions in ex-refinery prices following variations in the price of crude oil.

F. Cost of marketing and distribution : Being liquid and volatile in nature, petroleum products require special facilities for storage, transportation and distribution. The oil companies have to deliver their products like MS, HSD, ATF and LPG to respective dealers/agents, at retail pump outlets, air field stations etc. Retention prices for distributing and marketing agencies are fixed on the basis of certain efficiency norms of operation. The cost of marketing operations is reimbursed to the oil companies through marketing margins recommended by the committees set up by the government. In their absence the OCC is asked to review the marketing costs of oil companies.

G. Basic ceiling selling price - ex-storage points : In order to arrive at the ceiling selling prices of various petroleum products, following elements are included in the price build-up to arrive at uniform ex-refinery prices (inclusive of marketing and distribution margins).

(1) Excise duty
(2) Freight surcharge

H. Consumer prices : To the basic ceiling selling prices obtained above the following components are added for estimating consumer prices (on a uniform basis):

1. National railway freight upto various depots.
2. Transportation charges : from depots to retail pump outlets for MS/HSD; to agents/dealers for SKO/LDO.
3. Dealers commissions and retail pump outlets/air field station charges.
4. Sales tax.
5. Octroi tax and local levies.

However, with a view to subserve certain socio-economic objectives, the actual prices charged from consumers are fixed on the basis of 'differential pricing' concept. For instance, furnace oil and naphtha for use as fuel and feedstock are supplied at concessional rates to fertilizer industry as compared to other industries. Further, LPG is sold at lower prices for domestic use as against industrial use. SKO, a product of mass consumption by poorer sections of society for cooking and lighting, is made available at subsidised rates.

4.1.3 Behaviour of prices in the petroleum sector

Trend in petroleum prices vis-a-vis prices of other energy sources and wholesale prices is shown in Table 4.1.1 below.

Table 4.1.1 : Wholesale average price indices of petroleum products, energy and all commodities in India (1970-71 = 100)

Year	Petroleum Imported Crude Oil	Petroleum Crude and Natural Gas	Petrol/ Mogas	SKO	ATF	HSD	LDO	FO	All commodities
1970-71	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1971-72	125.3	130.2	116.5	105.3	121.2	103.3	106.5	111.4	105.6
1972-73	133.0	142.0	121.6	114.9	125.6	104.0	107.8	113.7	116.2
1973-74	329.0	317.1	178.6	123.1	173.9	105.2	122.0	150.7	174.9
1974-75	722.0	686.5	272.1	187.1	288.4	127.7	260.9	308.4	174.9
1975-76	848.4	700.3	282.8	209.6	296.5	160.1	267.7	377.8	173.0
1976-77	919.8	740.3	285.0	229.6	297.1	160.1	267.7	429.7	176.6
1977-78	944.0	987.6	286.4	229.9	297.8	160.3	267.9	429.7	185.8
1978-79	938.5	802.9	299.1	235.0	309.6	164.0	269.1	432.6	185.8
1979-80	1491.2	1384.4	361.3	266.1	431.7	186.5	329.8	529.9	217.6
1980-81	2264.8	2041.8	430.7	277.3	581.7	279.6	880.1	548.1	257.3
1981-82	2683.5	2130.7	505.5	315.2	589.6	373.3	732.5	1148.5	281.3
1982-83	2622.0	1984.8	517.5	328.1	593.4	389.5	760.8	1185.6	288.7
1983-84	2437.4	1739.5	522.6	343.0	593.4	414.9	800.1	1228.1	316.0
1984-85	2762.6	1739.2	642.6	410.4	688.8	452.2	929.3	1412.5	338.4
1985-86	2674.7	1752.1	612.2	347.2	688.9	440.2	929.3	1412.5	357.8
1986-87	1505.5	1577.1	642.6	410.4	688.8	452.2	929.3	1412.5	376.8
1987-88	1866.0	1079.1	660.6	410.4	690.8	450.7	929.3	1412.5	405.4
1988-89	1765.9	1079.1	734.0	410.4	891.0	450.7	929.3	1412.5	435.8
Average[(1)] rate of growth between 1970-71 & 1988-89 (%)	18.47	18.81	12.33	9.33	12.83	9.90	14.95	18.00	8.5

Source: [2]

(1) : Refers to average annual compound rate of growth between 1970-71 and 1988-89

A comparative examination of price trends in the petroleum sector vis-a-vis other petroleum products and all commodities is carried out for the years 1970-71 to 1988-89. From a comparison of imported and domestic crude oil prices it is observed that the relative movement of imported crude oil prices was lower than its indigenous counterpart only prior to 1973 oil crisis. Since then imported crude oil prices have risen at a rate faster as compared to the domestically produced one.(For more details see the following sub-section)

An examination of prices in the petroleum sector relative to wholesale price indices for all commodities reveals that during the period under consideration, the prices of major petroleum products have been rising at a steeper rate when compared with the general wholesale price indices, the only exception being SKO whose prices rose relatively slowly till 1979-80 but followed the general trend thereafter.

A comparison of prices within the petroleum sector reveals that there was a sharp increase in prices of crude oil and natural gas (18.81%), LDO (14.95%), furnace oil (18.00%) followed by a relatively moderate increase in prices of petrol/mogas, ATF & lubricants i.e. in the range of 10% to 13%. Lowest rates of price rise i.e. in the range of 8% to 9% are observed in case of kerosene, which is meant for cooking and lighting amongst poorer sections of the society and HSD, which is used as a fuel in public modes of transport.

The following table gives the trends in the movements of domestic and imported crude oil.

Table 4.1.2 : Prices of Imported and Domestic Crude Oil (Rs/mt)

Year	Imported	Domestic		Effective Date
		On-shore	Off-shore	
1970-71	91			
1971-72	114			
1972-73	121			
1973-74	300			
1974-75	657	270.04	-	01.04.1975
1975-76	772	305.41	-	08 09.1976
1976-77	837	305.41	433.65	16.12.1976
1977-78	859	305.41	433.65	
1978-79	854	305.41	433.65	
1979-80	1357	305.41	433.65	
1980-81	2061	324.41	452.65	01.04.1981
1981-82	2442	324.41 1182.00	452.65 1182.00	01.04.1981 11.07.1981
1982-83	2386	1382.00	1382.00	15.02.1983
1983-84	2218	1382.00	1382.00	
1984-85	2514	1513.00	1513.00	01.04.1984
1985-86	2435	1513.00	1513.00	
1986-87	1370	1813.00	1813.00	01.04.1987
1987-88	1684	1813.00	1813.00	01.02.1989
1988-89	1607	2113.00	2113.00	
1989 (Apr-Dec) (p)	2046	2113.00	2113.00	

Source: [2]
(p) : Provisional

An analysis of this leads to the following observations.

1. Price of domestically produced crude oil in India has been maintained below the international price. However, the ratio of imported price to domestic price reduced from 2.42 in 1974-75 to 1.61 in 1985-86, thus narrowing the divergence between the two. Thereafter, following the slump in international oil prices the imported crude oil prices have been lower than the price of indigenous crude oil.

2. The movement in indigenous crude oil prices is fairly independent of the behaviour of imported crude oil prices. For example, while the price of imported crude oil went up from Rs 1357/tonne in 1979-80 to Rs 2061/tonne in 1980-81 and subsequently to a still higher level of Rs 2442/tonne in 1981-82, the domestic prices were revised upwards only in July 1981 from a low value of Rs 324-452/tonne to Rs 182/tonne. Again, in spite of a dip in the price of imported crude oil from Rs 2435/tonne in 1985-86 Rs 1370/tonne in 1986-87, the domestic crude oil prices were raised from Rs 1513/tonne to Rs 1813/tonne during the same period by imposing a higher level of royalty and oil development cess. Subsequently, as the average import price of crude oil has shown an upward trend to reach a level of Rs 2046/tonnne in 1988 (Apr-Dec) the indigenous crude oil prices were revised in 1988-89 to a level of Rs 2113/tonne by raising the level of oil development cess.

3 There has been a consistent pattern which shows that government has been taking an increasing share of sales revenue by increasing the rate of royalty and oil development cess components of the delivered price of crude oil at the refineries. This is illustrated by the data on basic price, royalty and oil development cess which is given in Table 4.1.3.

4.2 Coal pricing in India

4.2.1 Evolution of coal pricing

History of administered coal pricing

Coal prices have been administered by the government since 1941 except for a seven year period of decontrol between 1967 and 1974. Price revisions until 1957 were linked to labour awards, when, following the clamour raised by industrial consumers regarding increases in costs of stores and the need to extract coal from deeper seams, the government set up the Coal Prices Revision Committee (CPRC) in May 1957. The CPRC, by concentrating on the Bengal-Bihar coal mining area (which accounted for 80% of total coal production in the country) observed wide divergences in costs and evolved norms in respect of each item of cost as the basis for their price recommendations.

Subsequently, two study groups were appointed in 1963 and 1965, to look into cost escalation. In August 1966 the government of India directed the Tariff Commission to investigate the problems encountered in pricing of coal and coke. However in July 1967, before the recommendations of the Tariff Commission were implemented, all controls over coal prices were lifted. This phase of decontrol lasted till 1974. During the phase of decontrol coal prices were mainly dictated by its principal buyers, namely railways for steam coal and steel plants for coking coal.

The coal sector was nationalised in 1973. Since then coal prices have been revised several times on the basis of recommendations of several committees and working groups set up by the government. In general all the committees have recommended that the pithead price of coal should be based on its average cost of production, with some return on the capital employed. A suitable allowance for cost escalations is also suggested. The basis for determining average cost of production has varied, depending upon the recommendations of different committees of the government. To quote a few - the Fernandes Committee (1973) price recommendations were based on average cost of production for the whole sector, excluding interest on debt, but including a 10% rate of return on capital. The Fuel Policy Committee (1974) suggested that coal mines in India be classified into certain geographical groups, and 'representative mine' be selected for estimating the 'bench-mark' cost of production. The average selling price of all coals from each geographical grouping should be set to assure a net rate of return of 10% on capital invested, after meeting the bench-mark cost The Chakravarty Committee price recommendations were based on estimated average cost of production in 1975-76, excluding interest on short-term non-plan loans, but allowing for a return of 5% on equity. Subsequently, the Baveja Committee(1978) on coal prices examined the increases in labour costs due to regularisation of casual labour after nationalisation. Since then, coal price revisions have largely been linked to escalations in average costs of production for the coal sector at large.

However, coal prices have usually been set below average cost of production due to following reasons:

1) exclusion of return on capital and/or depreciation from estimated average cost of production.

2) **insufficient allowance for escalation in input costs or delays in price adjustment.**

This is substantiated by the chronological information available on coal price revisions for Coal India Limited (Annexure 4.2.1). The data show that in response to the recommendations of the Fernandes Committee (1973), while the government based the price on estimated average cost of production, the proposal for a 10% rate of return on capital was rejected. Similarly, price revisions announced by the Government in July 1975, after the submission of the Chakravarty Committee Report, were based on estimated average cost of production excluding any allowance for depreciation, interest and return. Although, price revisions of 1979 allowed for a 10% rate of return on capital employed, Rs 2.87/tonne were deducted to reflect cost savings on account of moratorium on interest on non-plan loan. This practice persisted during the next two price revisions of February 1981 and May 1982. Thereafter, the price revisions of January 1984 and 1986 also did not include any return on investment

Consequently, the coal producers are incurring losses on account of exclusion of these components while determining the mine-head coal price The details of losses in revenue owing to disallowance of these items are also presented in Annexure 4.2.1.

Current procedure for coal pricing

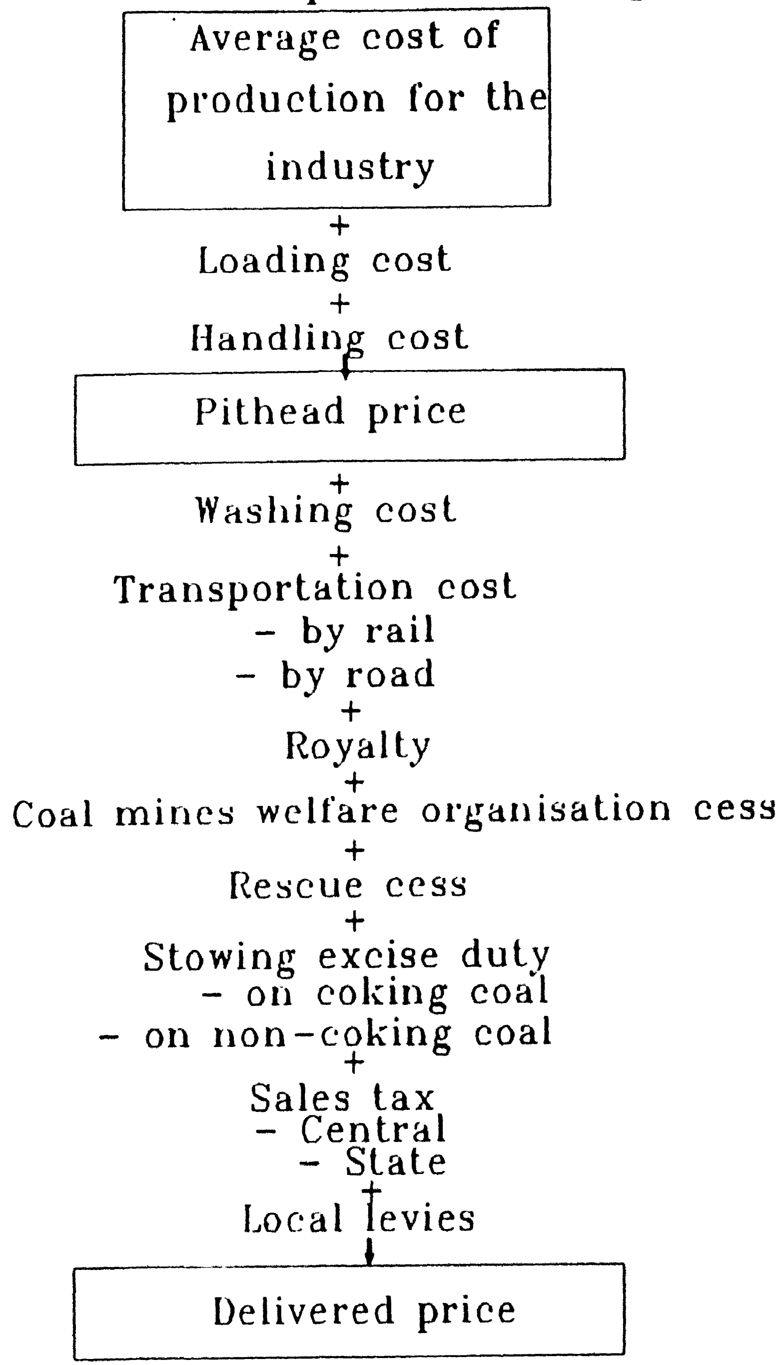
Presently, the pithead price of coal is based on average cost of production for the industry, differentiated between grades of coal depending upon properties such as ash content or useful heat value. To determine average cost of production certain subjective standards have been adopted as 'normative costs'[1] for each of the elements of production cost as described above. Pithead coal prices include loading and other handling cost Therefore, they can be called 'free on rail' (FOR) price. The pricing procedure focuses only on pithead costs with the delivered price of coal left largely uncontrolled.

Delivered price of coal to the consumer is determined by adding to the pithead price the transportation costs, taxes and duties. Due to geographical concentration of coal fields in the eastern part of India, coal is transported over long distances. The average length of a haul for non-coking coal to power stations, cement plants etc., delivered by rail, is as high as 650-700[11] kilometres while that for coking coal is much shorter because steel plants are located relatively close to the coal fields. Hence, the share of transportation costs in total delivered price (especially in case of non-coking coal) is quite high. Besides, the delivery price of coal is also inclusive of royalty payments, local cesses, excise duties and central and state taxes. A detailed price build-up of coal is presented in the figure 4.2.1 below.

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[1]Price of coal has to be fixed with reference to the cost of production. Since these elements of cost are widely varying for different collieries, certain subjective standards, what might be regarded as'reasonable norms' for each item of the cost of production, have been adopted. These 'normative costs' are close to the mean of observations of cost of producing coal in India.

Figure 4.2.1 : Market price build-up of coal



4.2.2 Classification of coal (by type and grade)

Coal prices at the pithead vary with quality. According to the prevailing grading system non coking coal is classified into seven grades based on its Useful Heat Value (UHV). The UHV is assessed on the basis of a prescribed formula[2] from gross calorific value, by imposing a penalty for different percentages of ash and moisture content.

Coking[3] coals are divided into two categories - coking and semi-coking. Coking coal is further subdivided into six grades based on ash content, varying from less than 15% to 35%. Semi-coking coals are 'blendable[4] coking coal. They are divided into two grades on the basis of percentage of ash and moisture content.

A detailed classification of coal is presented in the following figure.

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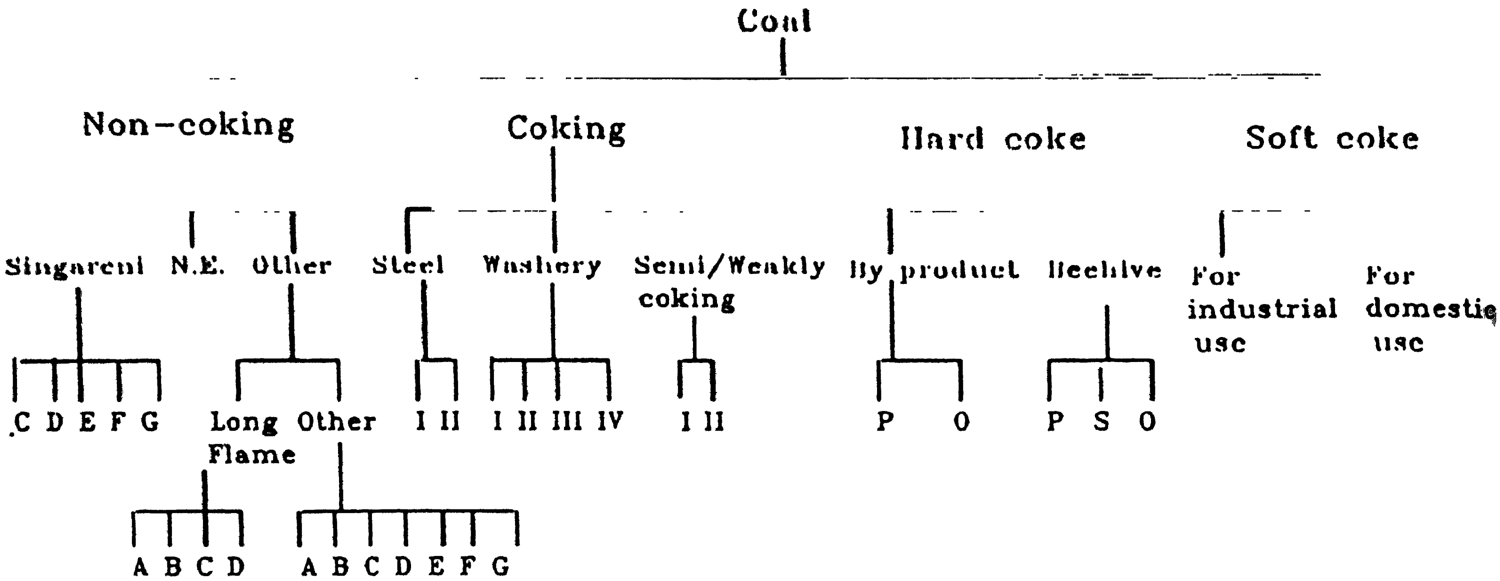
[2]Useful Heat Value (UHV) is defined by the following formula

UHV = 8900 - 138 (A + M)
UHV = Useful Heat Value in kilocalories per kilogram
A = Ash Content in percentage
M = Moisture Content in percentage

[3]Coking coals are obtained by thermal decomposition of coal, which is a complex sequence of events described as the 'carbonisation process'. As a result of carbonisation volatile matter and a part of moisture present in coal gets released as gases and a toughened devolatised solid fuel, with a honey-comb like structure, is formed. The porous structure thus developed allows a regular flow of air through its pores and facilitates burning in the furnace.

[4]Semi-coking coals, due to their favourable low ash content, are blended with coking coals to improve the latter's physical and chemical properties so as to enable a proportion of inferior or marginal coking coals to be employed as feeds to improve the yield of coke.

Figure 4.2.2 : Classification of coal



P – Premium
S – Superior
O – Ordinary

4.2.3 Present price structure for coal at the pithead

In pursuance of clauses 3 and 4 of the Colliery Control Order, 1945 the central government on and from 1st January 1989 has prescribed the price structure given in Table 4.2.1 for coal to be sold by colliery owners at pithead. The pithead prices are exclusive of royalty, cesses, taxes and levies imposed by central or state government, local authorities or other bodies.

Table 4.2.1 : Price of coking coal		
Grade	Ash content	Sale price of Slack Coal(5)[(1)] (Rs/tonne)
Steel Grade I	= < 15%	654.00
Steel Grade II	= < 18%	546.00
Washery Grade I	= < 21%	473.00
Washery Grade II	= < 24%	393.00
Washery Grade III	= < 28%	303.00
Washery Grade IV	= < 35%	283.00
Semi-Coking Grade I[(2)]	= < 19%	473.00
Semi-Coking Grade I	= < 24%	393.00

Source : [4]
[(1)] Price of steam coal and rubble[5] is higher by Rs 7/tonne for all grades of coking coal; price of run-of-mine(5) coal is lower by Rs 3/tonne for all grade
[(2)] When ash plus moisture content of semi-coking coal grade I is less than 17%, the prices payable for it, as per above table, shall be increased at the rate of Rs 5/- for every 1% decrease in ash plus moisture content below the 17% fraction on pro-rata basis.

[5]Run-of-mine coal comprises all sizes as it comes out of the mine, without any crushing or screening. The fraction of run-of-mine coal retained on the screen when subjected to screening or picked out by a fork shovel during loading is called steam coal. The fraction that remains after steam coal is removed from run-of-mine coal is called slack coal.

Table 4.2.2 : Price of non-coking coal (Unit : Rs/tonne)

Grade of Coal	Useful Heat Value (kcals/kg)	Sale price of Slack Coal and Washery Middlings[1]
Long flame* coal produced in all states[2]		
Grade A	>=6200	427.00
Grade B	5600-6200	392.00
Grade C	4940-5600	346.00
Grade D	4200-4940	280.00
Other coal produced in all states[2]		
Grade A	>=6200	402.00
Grade B	5600-6200	367.00
Grade C	4940-5600	321.00
Grade D	4200-4940	255.00
Grade E	3360-4200	203.00
Grade F	2400-3360	163.00
Grade G	1300-2400	117.00
Coal produced in State of Andhra Pradesh (Singareni coal fields)		
Grade C	4940-5600	363.00
Grade D	4200-4940	320.00
Grade E	3360-4200	271.00
Grade F	2400-3360	205.00
Grade G	1300-2400	160.00
Coal produced in states of Assam, Meghalaya, Nagaland and Arunachal Pradesh.		460.00

Source : [4]

[1] When the UHV of non-coking coal is greater than 6400 kcal/kg the price payable for grade A shall be increased at the rate of Rs 1 for every 100 kcals by which the actual UHV exceeds 6400 kcals/kg. The price of steam coal and rubble are higher by Rs 7/tonne for each grade of non-coking coal; price of run-of-mine coal are lower for each grade.

[2] Excludes Assam, Meghalaya, Nagaland and Arunachal Pradesh.

'Long Flame Coals' may be defined by the parameters laid down in Indian Standard No. IS:770-1964-"General Classification of Coals (Revised)". The relevant part is extracted below:

Group	Volatile Matter percent (unit coal basis)	Range of Gross calorific value coal basis)	Range of Dried moisture present in kcal/kg (unit 60% RH at 40°C
B4	over 32	8060 to 8440	3 to 7
B5	over 32	7500 to 8060	7 to 14

Some features to be noted in this respect are :

1) Prices set for comparable grades of coal produced in Singareni coalfields is higher than for coal produced in other states. Though the quality of coal mined by Singareni Colliery Company Limited (SCCL) is largely of poor quality (see Annexure 4.2.2), it commands a higher price due to its locational advantage. It is argued that since SCCL supplies coal to power stations located in southern parts of India it charges a premium which the power houses will have to pay to procure coal from elsewhere.

2) The prices set for coal produced in Assam, Meghalaya, Nagaland and Arunachal Pradesh are higher than those for other states. This is primarily because of relatively good quality and low ash content coal mined from NECL which is being used for blending with high ash coking coal in the steel plants (see Annexure 4.2.3). Higher prices can partly be attributed to difficult geological and mining factors resulting in higher costs of production.

4.2.4 Historical trend in coal prices

An examination of the relative movement of prices of coal as compared to all commodities revealed that in the pre- nationalisation period, the index of coal prices moved more or less together with the general wholesale price index. However, ever since the coal industry was taken over by the public sector, the rate of increase of coal prices has been higher (especially after 1979-80) as compared to the general rise in wholesale prices for all commodities put together.

Table 4.2.3 : Index number of wholesale prices (Base : 1970-71 = 100)

Year	General Index of Wholesale Prices	Coal	Coal deflated by GWPI
1970-71	100.00	100.00	100.00
1971-72	105.60	102.00	96.60
1972-73	116.20	111.00	95.52
1973-74	139.20	122.00	87.64
1974-75	174.90	144.00	82.33
1975-76	173.00	184.00	106.36
1976-77	176.60	198.00	112.12
1977-78	185.80	199.00	107.10
1978-79	185.80	212.00	114.10
1979-80	217.60	300.00	137.87
1980-81	256.20	348.00	135.83
1981-82	281.30	432.00	153.57
1982-83	288.70	493.00	170.77
1983-84	316.00	542.00	171.52
1984-85	338.40	642.00	189.72
1985-86	357.80	662.00	185.00
1986-87	376.80	731.00	194.00
1987-88	405.40	766.00	188.95

Source : [5]

Table 4.2.4 : Average pithead price of coal (Rs/tonne)	
Year	Price
1950	14.81
1955	14.46
1960	20.75
1965	23.78
1970	35.68
1971	32.83
1972	36.41
1973	40.60
1974	51.46
1975	70.42
1976	70.14
1977	70.63
1978	70.37
1979	90.57
1980	118.95
1981	143.49
1982	157.26
1983	166.05
1984	204.87
1985	206.88
1986	229.28
1987	229.28
1988 (upto March)	227.78
Source: [3]	

The data on average pithead price of coal in Table 4.2.4 shows that coal prices remained fairly low and the escalation in them was steady during 1950s and 1960. The average pithead price of coal per tonne increased at an annual compound rate of 3.43% between 1950-60 and 5.57% during 1960-70. However,

the period after the nationalisation of coal sector starting 1973 experienced sharply rising prices, registering an average annual rate of growth of 12.8% between 1970-80 and around 9.09% between 1980-88. These price revisions in the post-nationalisation period, can be attributed to a number of factors, some of which are discussed below:

1) It is argued that price escalations are mainly because of high investments going into the coal sector, especially in the post-nationalisation period. The capital expenditure on amalgamation and reconstruction of the industry together with those on new mining projects, with advanced mining techniques (which are both capital intensive and have large gestation periods) are largely responsible for rising allocations in the coal sector.

Table 4.2.5 : Plan investment allocations in the coal sector (Rs million)

Plan	Allocations
I (1951-56)	-
II (1956-61)	400
III (1961-66)	1030
IV (1969-74)	1150
V (1974-79)	11470
VI (1980-85)	20700
VII (1985-90)	74010

Source : [7]

It is evident from the table above that planned investments in the coal sector rose from a low level of Rs 400 million during the II plan to Rs 1150 million during the III plan. They went up to a high value of Rs 11470 million during the V plan, Rs 20700 million during the VI plan and Rs 74010 million in the VII plan. These investments are quite high, even after adjusting for general price rise. The actual outlays in the coal sector are still higher.

2) The salaries and wages are the most important component of total cost of production. It is apparent from Table 4.2.6 below that remuneration paid to labour has risen at a rate faster than labour productivity in the post-nationalisation period.

Table 4.2.6 : Output per manshift (OMS) and earnings per manshift (EMS) in Indian coal sector (Base=1974-75)						
Year	OMS (Tonnes)	Index of OMS	EMS (Rs)	Index of EMS	Total cost (Rs tonne of net saleable coal	Index of total cost
1974-75	0.58	100.0	21.67	100.0	58.82	100.0
1975-76	0.66	113.8	27.97	129.1	70.10	111.2
1976-77	0.67	115.5	28.65	132.2	75.66	128.6
1977-78	0.68	117.2	31.81	146.8	82.46	140.2
1978-79	0.67	115.5	34.66	160.0	95.09	161.7
1979-80	0.68	117.2	43.72	201.8	110.04	187.1
1980-81	0.72	124.1	50.32	232.2	123.12	209.3
1981-82	0.77	132.8	54.96	253.6	137.15	233.2
1982-83	0.79	136.2	58.82	271.4	152.02	258.5
1983-84	0.82	141.4	79.17	365.3	183.70	312.3
1984-85	0.87	150.0	85.20	393.2	190 63	324.1
1985-86	0.92	158.6	91.35	421.6	213.97	263.8
1986-87	0.99	170.7	106.70	492.4	221.54	367.6
Source : [2]						

4.2.5 Some disquieting features of coal pricing in India

The present structure of coal pricing of CIL is not quite rational. The following Table 4.2.7 contains the prevailing prices set for different grades of non-coking coal, classified according to their heat value.

Table 4.2.7 : Price per unit of useful heat value for non-coking coal

Grade	Price Rs/tonne	Price per unit of Slack Coal Rs/10^6kcal
Long flame coal produced in all states		
Grade A	427.00	68.87
Grade B	392.00	70.00-63.22
Grade C	346.00	70.04-61.78
Grade D	280.00	66.67-56.68
Other coal produced in all states		
Grade A	402.00	64.84
Grade B	367.00	65.55-59.19
Grade C	321.00	65.00-57.32
Grade D	255.00	60.71-51.62
Grade E	203.00	60.41-48.33
Grade F	163.00	67.91-48.51
Grade G	117.00	90.00-48.75
Coal produced in State of Andhra Pradesh (Singareni coal fields)		
Grade C	363.00	73.48-64.82
Grade D	320.00	76.19-64.78
Grade E	271.00	80.65-64.52
Grade F	205.00	85.54-61.01
Grade G	160.00	123.08-66.67
Coal produced in states of Assam, Meghalaya,Nagaland and Arunachal Pradesh.		
		83.64

Some important features that emerge are:

1) **There is a glaring discrepancy observed in the present price structure of non-coking coal, whereby some of the inferior grades of coal are priced higher per unit of heat value as compared to superior grades of coal. For example long flame coal of grade B and C cost more than grade A, while in case of other coals prices for lower grades, especially grade G are fixed much higher as compared to higher grade coals. This distortion is particularly noticeable in case of coal from Singareni coalfields of Andhra Pradesh.**

2) There is no systematic or logical principle adopted for inter-grade price differentials. A rational pricing structure should have an in-built allowance to adequately compensate the consumers for using lower quality coal, which is not the case here.

3) Finally, a uniform price is charged for coal within each grade (with widely varying heat value). This is based on the lowest UHV (in kcal/kg) in the specified range of each grade, with the result that it provides no incentive to coal producers to supply coal with higher heat value covered in the grade. Hence, there are regular complaints launched by coal consumers that coal supplies received by them contain large quantities of extraneous matter causing damage to their machinery and equipment.

Coal prices are administered and are intended to cover the average cost of production with the funds for capital expenditure being provided by the government. However, in practice, ever since the nationalisation of coal sector, the cost of sales have generally been higher than the net sales revenue with the result that coal companies have been incurring losses and are dependent on the government, not only for capital expenditure funds but also for financing cash losses.

This is quite evident from the financial accounts of the coal sector for different years which are summarised in table 4.2.8 below :

Table 4.2.8 : Trends in revenue, costs and profit/loss in the coal sector						
Year	Net Saleable Production (Lakh tonnes)	Sale Value (Rs/tonne)	Total Cost (Rs/tonne)	Profit/ Loss (Rs/tonne)	Overall[(1)] Profit/ Loss (Rs/tonne)	Overall Profit/ Loss (Rs lakhs)
1974-75	755.31	48.84	58.82	-9.98	-9.98	-7537.99
1975-76	845.31	64.17	70.10	-5.95	-5.93	-5012.68
1976-77	844.75	66.30	75.66	-9.36	-9.84	-8312.34
1977-78	835.94	66.49	82.46	-15.97	-16.60	-13876.60
1978-79	827.95	65.47	95.09	-29.62	-30.02	-24855.00
1979-80	849.03	100.72	110.04	-9.32	-10.64	-9033.67
1980-81	937.34	120.69	123.12	-2.43	-3.06	-2868.26
1981-82	1015.12	138.09	137.15	0.94	0.52	527.86
1982-83	1095.39	155.77	152.02	3.75	3.38	3702.42
1983-84	1164.17	159.98	183.69	-23.71	-24.88	-28964.50
1984-85	1256.04	188.18	190.63	-2.45	-6.64	-8340.10
1985-86	1286.94	190.87	213.97	-23.10	-27.98	-36008.50
1986-87	1389.28	202.80	221.54	-18.74	-22.01	-30578.00

Source : [2]
(1) Inclusive of profit/loss on coal, washeries, hard coke, soft coke etc.

Recurring financial losses of coal companies can be attributed to a number of factors, some of which are discussed as follows :

1) Being a labour intensive sector, production depends on labour management. The labour productivity, usually measured by output per manshift (OMS), takes into account manshifts engaged in underground and opencast mining operations, administrative/managerial and other services of the coal companies and manpower employed in social activities (such as schools, water supply, post and telegraph, etc.).

The following Table 4.2.9 gives trends in output per manshift (OMS) in India vis-a-vis major coal producing countries of the world.

Table 4.2.9 : International comparison of trends in output per manshift (OMS)						
	India	Australia	USA	W.Germany	Japan	France
1956	0.39	3.79	8.67	0.95	0.50	0.98
1961	0.46	6.76	11.73	1.33	0.71	1.15
1966	0.56	9.12	16.06	1.67	1.18	1.31
1971	0.67	9.91	15.90	2.25	1.74	1.52
1976	0.69	11.85	11.49	2.44	1.82	1.56
1981	0.81	12.59	12.88	2.92	2.03	1.94
1984	0.90	16.40	16.30	3.11	2.12	1.94
Source : [11]						

Due to increasing modernisation and mechanisation in mining, OMS in India rose steadily from a low level of 0.39 tonnes per manshift in 1956 to 0.90 in 1984. However, trends in labour productivity are much below those observed for other coal producing countries of the world.

2) Though coal prices have been adjusted from time to time on the basis of recommendations of various committees and groups, they have generally been set below average cost of production due to either exclusion of return on capital or depreciation from average cost of production estimates or inadequate or delayed revisions to take care of increases in cost of inputs. Consequently, average sales realisation for coal India has been lower than the average cost resulting in losses incurred by coal producing and selling sector.

4.3 Electricity pricing in India

~~4.3.1 Pricing policies~~

Electricity pricing is the responsibility of the SEBs. The electricity tariff of the SEBs is to be primarily based on considerations contained in section 23 of the Indian Electricity Act 1910, and section 40 and 59 of the Electricity (Supply) Act 1948. Under the Electricity (Supply) Act of 1948, the board has to carry on its operations, as far as practicable, without incurring losses and the board could, from time to time, adjust its tariffs. The Act, however, did not mention any surplus that the board was expected to generate.

The Electricity (Supply) Act 1948 was amended in 1978 to make SEBs commercially viable and to earn a net return on their investment. In accordance with the amendment, SEBs were to carry out their operations and adjust tariffs so as to ensure that total revenues in any year have such surplus as the State Government may from time to time specify. There was another amendment to the Act in 1980, which specified that the SEBs should earn a net return of 3% on the net assets as at the beginning of the financial year.

Several committees have been constituted in the past with the prime objective of analysing the financial performance and pricing policies of the power sector and to make recommendations to improve the operational and financial performance of the SEBs. Some of the recommendations of a few committees set up in the past are given below.

1. A working group set up by the Planning Commission in 1963 on pricing policy of the state electricity undertakings had recommended that the SEBs should earn a return of 12% (including electricity duty) on capital investments after providing for operating expenses and depreciation.

2. Venkataraman Committee in 1964, recommended a rate of return of 11% on the capital employed and suggested that this rate of return should be achieved in a phased manner within next 10 years. This return was to be computed after providing for operating costs and depreciation. The net return worked out to be about 3%, after providing for interest charges (6%), transfer to general reserve (0.5%), and electricity duty (1.5%). In several discussions with the World

   Bank, a rate of return of 11% as recommended by Venkataraman Committee had been mutually agreed upon.

3. Responding to the rise in interest burden the Rajadhyaksha Committee, in 1980, recommended a rate of return of 15% on the average capital employed.

Pricing of electricity in Indian electric utilities have generally been based on the principle of recovering average cost of supply. While laying down the tariffs, the SEBs have to take into consideration

the policies and objectives of their state governments. As a consequence tariffs are often weighted more by social considerations rather than financial considerations and one finds that tariffs for some consumer categories are set at a rate even lower than the average cost of generation and supply to them. Table 4.3.1 gives the details of average cost of generation and supply in various SEBs and average revenue realized from major consumer categories in 1989-90. It is evident from the table that agricultural consumers are supplied electricity at a highly subsidized rates. Table 4.3.2 shows that over the years, though the share of agricultural sector in total consumption has been rising, the average rate for sale of electricity to this sector has declined in most of the states.

Table 4.3.1: Average cost of electricity generation and supply and average rate of realisation in major states : 1988-89 (paise/kwh)

State	Avg. cost of generation and supply	Avg. rate of realisation					Overall average realisation
		Domestic	Comm.	Agri.	LT-industry	HT-industry	
APSEB	65.4	52.3	111.4	4.5	111.4	94.9	60.8
ASEB	257.0	60.0	110.0	50.0	62.0	87.0	91.9
BSEB	149.2	57.3	94.6	9.4	171.2	132.5	93.5
GEB	102.5	67.8	67.8	24.8	113.8	116.2	82.9
HSEB	81.2	56.0	116.0	30.0	100.0	109.0	59.8
HPSEB	91.0	43.5	82.5	20.0	71.6	71.6	56.6
J&K	118.4	30.0	75.0	10.0	40.0	-	40.9
KEB	74.6	63.0	162.3	11.6	103.3	90.1	72.6
KSEB	66.6	48.7	78.0	22.0	60.0	57.9	56.3
MPEB	83.6	27.6	100.1	23.2	87.0	94.3	73.5
MSEB	87.9	47.0	89.0	9.0	76.0	118.0	80.0
MEGHALAYA	99.9	44.4	68.0	21.0	55.0	55.0	50.0
OSEB	66.2	44.0	92.0	22.1	53.3	65.9	65.6
PSEB	97.9	67.9	95.4	8.4	68.8	61.3	44.0
RSEB	98.5	58.2	107.4	29.5	83.7	91.8	81.1
TNEB	89.6	52.1	106.0	11.2	98.0	85.0	63.7
UPSEB	99.8	65.5	85.1	22.7	103.0	114.9	68.0
WBSEB	123.5	58.5	102.0	25.6	77.8	130.1	95.2

Source : [5]

Average revenue realised from sales of electricity to the domestic sector also continues to be below costs in all the SEBs (refer Table 4.3.1 for details). In 1989-90 the ratio of average rate of realisation from domestic consumers and average cost of generation was highest for Karnataka, where the average revenue realised from domestic consumers covered 84 per cent of the cost of supplying electricity to them.

In 7 out of 18 SEBs this ratio was less than 0.5 in 1989-90.

Table 4.3.2 : Average rate for sale of electricity and proportion of total sales to the agricultural sector (paise/kWh)

Board	1980-81	1985-86	1986-87	1987-88	1988-89	1989-90
APSEB	19.8 (19)	5.7 (24)	4.9 (28)	4.[illegible] (34)	4.[illegible] (32)	4.5 (29)
BSEB	25.0 (12)	11.4 (17)	10.6 (25)	9.6 (26)	9.4 (26)	9.4 (26)
GEB	27.4 (18)	53.1 (19)	57.3 (21)	22.1 (31)	27.7 (25)	24.8 (28)
HSEB	17.1 (37)	20.1 (32)	17.4 (36)	16.8 (43)	28.0 (40)	30.0 (39)
KEB	22.4 (8)	8.4 (25)	9.3 (28)	11.5 (30)	11.6 (20)	11.6 (19)
MSEB	34.3 (12)	27.7 (17)	23.5 (18)	23.2 (18)	23.2 (19)	23 2 (19)
PSEB	10.0 (37)	11.4 (36)	9.0 (40)	9.0 (44)	9.2 (39)	8.4 (39)
TNEB	16.3 (28)	11.2 (29)	11.6 (27)	11.8 (30)	11 2 (28)	11.2 (29)
RSEB	19.2 (34)	24.8 (29)	27.5 (27)	22.4 (30)	29.5 (28)	29.5 (29)
UPSEB	18.3 (36)	27.9 (31)	27.6 (36)	24.6 (41)	22.7 (39)	22.7 (36)

Note : Figures in brackets are the%age of total sales to agriculture sector
Source : [5]

In order to partially make up for the losses that SEBs incur as a result of subsidy provided to agricultural and domestic consumers, industrial and commercial consumers are often charged a rate higher than average cost of supply to them. In several states the average revenue realized from the commercial sector is even higher than that realized from industries. However, inspite of charging high tariffs to commercial and industrial consumers to compensate for low tariffs charged to agricultural and domestic sector, per unit average revenue realized is less than the average cost of generation and supply in most of the SEBs. Table 4.3.3 gives the trend in per unit surplus/deficit for the SEBs for the period 1985-86 to 1989-90. In 1989-90, the losses were highest in Assam (163 paise/kWh) followed by J&K (74 paise/kWh). Both Kerala and Madhya Pradesh who earned a surplus in 1985-86 had a loss of 9.7 paise/kWh and 5.8 paise/kWh respectively in 1989-90. In Punjab, J&K and Meghalaya, the losses have increased significantly during the period 1985-86 to 1989-90, whereas the losses have gone down in Madhya Pradesh, Maharashtra, Andhra Pradesh and Orissa.

Table 4.3.3 : Unit surplus(+)/deficit(-) (paise/kWh)					
State	1985-86	1986-87	1987-88	1988-89	1989-90
Andhra Pradesh	-0.9	-4.4	0.2	0.2	-1.8
Assam	-104.6	-123.9	-117.9	-138.9	-163.1
Bihar	-50.0	-57.2	-59.2	-51.4	-50.8
Gujarat	-12.6	-6.8	-11.6	-12.9	-16.8
Haryana	-18.4	-20.4	-36.5	-18.5	-15.7
Himachal Pradesh	-28.9	-31.6	-55.2	-51.4	-29.7
Jammu & Kashmir	-46.4	-50.6	-59.5	-63.7	-74.1
Karnataka	-3.5	-9.6	-12.6	-2.7	-1.4
Kerala	1.2	-4.4	-4.6	-13.8	-9.7
Madhya Pradesh	4.4	-1.4	-4.7	-4.9	-5.8
Maharashtra	-2.8	2.5	3.1	-3.9	-5.9
Meghalaya	-9.5	-37.8	-10.8	-31.5	-48.7
Orissa	-6.8	-4.9	-12.6	-5.7	0.7
Punjab	-19.0	-24.5	-35.8	-46.0	-50.0
Rajasthan	-12.0	-10.1	-16.2	-10.2	-12.4
Tamil Nadu	-17.4	-12.4	-16.8	-21.7	-24.7
Uttar Pradesh	-25.6	-21.7	-26.2	-35.1	-30.2
West Bengal	-24.1	-20.5	-26.4	-24.6	-25.3
Source : [5]					

The SEBs have accumulated losses mainly due to subsidised supply to the agricultural and domestic consumers (see Table 4.3.4). The boards do recover some of these losses through higher rates from LT-industrial, commercial and HT- consumers; the boards are also partly compensated for losses from agricultural supply with a subsidy from the State Government. While the principle of cross-subsidization is generally accepted, there is a limit to which this can be done. Calculations show that it is possible to make domestic category self-sufficient; this would require existing rates to go up only by an average of 10-20 per cent in several states. A suitably designed block tariff can achieve this objective.

Table 4.3.4 : Estimates of losses from domestic and agricultural sectors and total commercial profits/loss, 1987-88			
SEB	Losses to		Total commercial profit/loss (+/-) (Rs lakhs)
	Agriculture (Rs lakhs)	Domestic (Rs lakhs)	
Andhra Pradesh	228.5	15.2	3.45
Bihar	143.8	25.4	-290.03
Gujarat	262.9	25.2	-144.59
Harayana	160.5	31.2	-188.19
Karnataka	177.1	21.7	-103.45
Madhya Pradesh	55.7	74.0	-53.4
Maharashtra	292.0	59.6	47.31
Punjab	311.5	13.3	-345.49
Rajasthan	104.6	12.5	-99.94
Tamil Nadu	224.1	43.1	-230.54
Uttar Pradesh	405.3	45.5	-379 29

4.3.2 Tariff structure

Though the state utilities have their own set of tariffs, the structure of tariffs are broadly similar. Consumers availing supply at low voltage (e.g. residential, commercial etc.) are generally charged an average energy rate (paise/kwh) for the energy consumed and are billed for the energy they consume during a fixed period (generally 2 months). Most of the SEBs have a two-part (demand charge as well as energy charge) tariff for the industrial high voltage consumers (large industries, large business consumers, water supply, traction etc.). These consumers are charged an energy rate for the energy consumed during the billing period (normally one month). In addition, they are also charged a demand rate based on the maximum demand (MD) reached during the billing period. A point to note is that the MD charge is generally not related to the time of incidence of maximum demand.

LT industrial consumers are differentiated on the basis of either the connected load or on the basis of BHP connected. Consumers with a higher connected load are charged a higher rate. The wide variation in rates across states is to be noted. The HT consumers are categorised on the basis of voltage of supply and/or the contracted demand. All boards have a power factor correction clause for HT and LT consumers. While most of the boards have a penalty for low power factor, Gujarat Electricity Board is one board which provides an incentive for improving the power factor.

Agricultural tariffs have always been the subject of considerable discussion. This category of consumption has a very significant seasonal influence. In addition, the load is scattered and the annual level of utilization is comparatively low. All boards have followed a policy of subsidized rates for agricultural consumers. Apart from the overall tariff being much below the average costs, another important feature of agricultural tariff is that it is framed in the form of a "flat rate" tariff. The consumers in this category are charged a flat rate based on their connected load (per HP of pumpset) irrespective of the number of hours used or energy consumed. This is against the basic economic principles, as the marginal cost of usage of the pumpset is zero in such a case. Also flat rate tariffs encourage misuse and wastage of electricity. There are several instances of farmers running small industries on agricultural connection.

Most of the utilities, today, have moved from a simple energy rate to differential rates for different blocks of consumption. Inverted block tariffs are used to discourage consumption, as consumers have to pay an increasing charge for consuming more. This also takes care of the social objective of providing electricity at a low cost to consumers in the low income categories. There are one or two states who have decreasing block rates for domestic consumers. This is mainly done with a view to promote consumption amongst domestic consumers.

All boards have a fuel adjustment clause in their tariffs. But the increase in costs is passed on to all categories other than domestic, agricultural and LT industry categories. However, in Gujarat, fuel cost increases are passed on to all consumer categories. In Bihar, apart from HT consumers, the LT industry category also bears a share of the increase in fuel cost.

Tariff revisions by SEBs are generally carried out on an ad hoc basis. The additional costs to be recovered are calculated first. Based on this, the extent to which rates for HT-consumers is to be raised is decided. The balance cost to be recovered is then adjusted to the extent possible from the LT-industrial and LT-commercial and domestic consumers. The agricultural consumers are subjected to tariff revisions only if there is no other alternative.

The present tariff structure in most of the SEBs is not remunerative enough to enable the boards to earn even the statutory 3% rate of return. The SEBs get a subsidy from the state governments for meeting part of the losses incurred by supplying to consumers below cost. This poses serious constraints on the resources that are required for adding to capacity, particularly in view of the increasing cost of capacity addition. Also, the low levels of tariffs have encouraged high demand for electricity. An appropriate tariff structure can play a significant role in demand management and electricity conservation.

CHAPTER 5

ESTIMATION OF ECONOMICALLY EFFICIENT PRICES

5.1 Petroleum products

5.1.1 Introduction

In case of the petroleum sector it was decided that the price of petroleum products be related to the cost of oil production of refining, transportation, marketing and distribution activities. However, data on the cost of production of crude oil from different regions was not readily accessible. Further, detailed refinery-wise data on refining costs was for the year 1983-84 (Report of OCRC 1984) and hence rather old.

In the absence of any updated cost information, it was decided to determine price of petroleum products on "import parity" basis. In case of importables the shadow price would be the c.i.f. price inclusive of a premium on foreign exchange outflow while in case of the exportables, the efficient price would be its f.o.b. price. Most petroleum products are traded/tradeable commodities. Hence, in our analysis the price of these products was based on their border price.

Furthermore, in case of the imported products, the costs of receiving & supplying the product to the ultimate consumer were also added on. These include the cost of port handling, transportation, storage, marketing and distribution.

5.1.2 Data base

The data on c.i.f. price of petroleum products for 1987-88 were compiled from several sources. The c.i.f price of MS, FO and SKO were obtained from the "Office Memorandum, World Bank/IFC, 5 March, 1990". The c.i.f. prices of other petroleum products were compiled from the 'Indian Petroleum and Natural Gas Statistics, 1987-88'.

The economic costs pertaining to the handling of imports at ports, storage/tankage facilities, bottling of LPG and distribution by wholesalers and retailers were obtained from the study carried out by TERI (1989). [5]

The estimates of resource/economic cost of transporting oil products by different modes viz. railways, highways and coastal shipping were taken from a report by RITES [4] prepared for the Planning Commission (GOI). These were available for different distance slabs. The costs of pipeline transportation (for existing and new pipelines) were considered as estimated by the afore-mentioned study carried out by TERI. [5]

The kilometer distances by rail and road and the length of pipelines connecting the different points of origin and destination were collected from various sources. The coastal distances between major ports of India were obtained from the Indian Ports Association, New Delhi.

5.1.3 Methodology

The steadily rising demand for oil products has necessitated their import at the margin. Therefore the c.i.f. price inclusive of foreign exchange premium (to reflect the scarcity of foreign exchange reserves) was considered as the starting point for computing the economic cost of supplying individual products to the consumers.

Considering the uncertainty in international oil price movements, historical data were used for analysis. All prices and costs pertain to 1987-88. The economically efficient price is determined for individual fuels such as MS, ATF, HSD, FO, SKO, LPG etc.

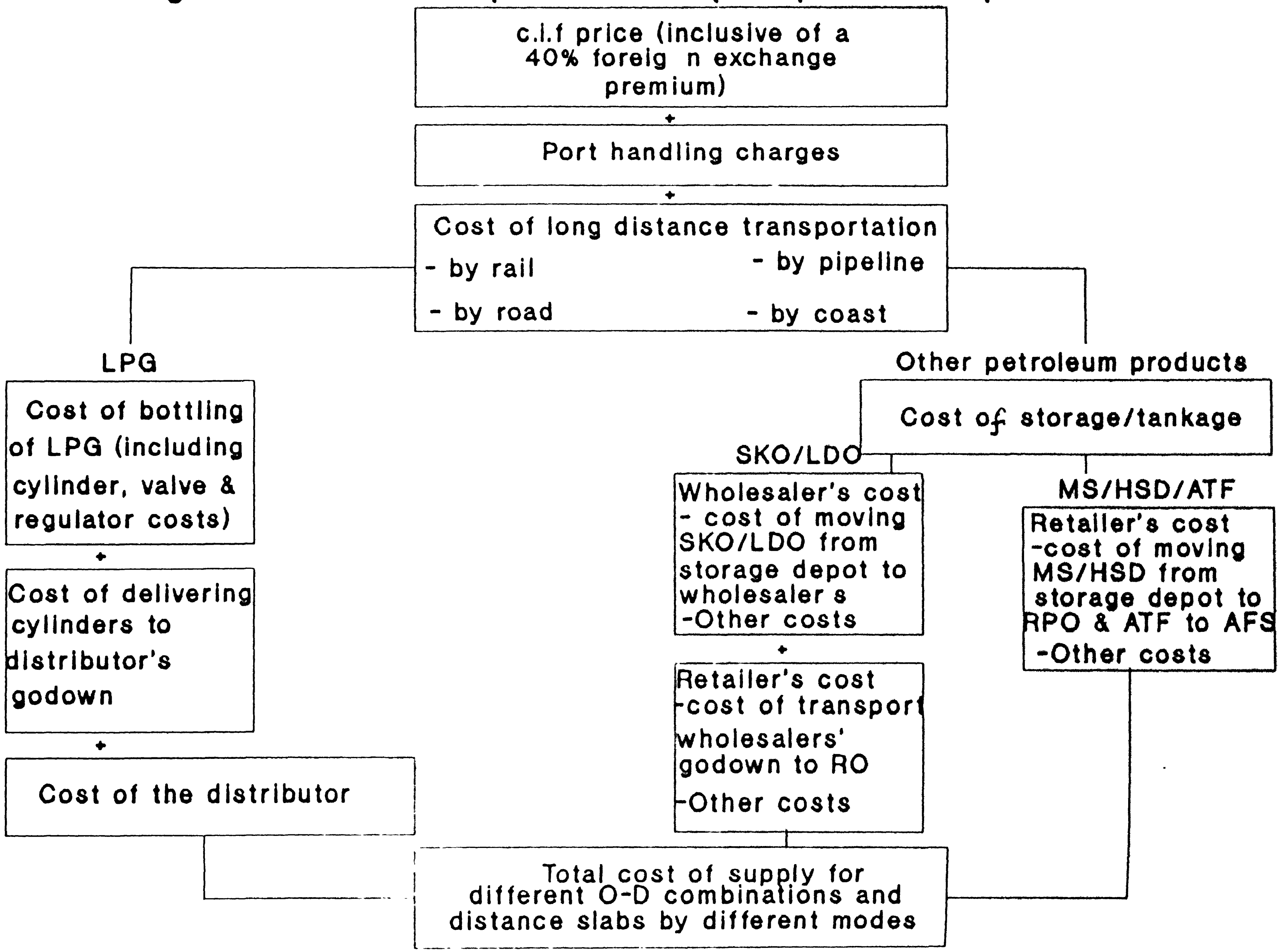
To the c.i.f. price were added the costs of handling imports at ports, transportation, storage/tankage facilities, bottling of LPG, marketing and distribution by intermediaries etc. to arrive at the efficient supply price of the fuel. This price was computed for different combinations of source/origin (port of landing) and destination (town/city of consumption) combinations in addition to being computed for various distance slabs from the supply points. The place of origin refers to the port cities such as Bombay, Madras, Vishakhapatnam, Haldia and Mangalore where the product imports would be received. The points of destination refer to the towns/cities such as Bombay, Delhi, Madras, Calcutta, Kanpur, Vishakhapatnam and Haldia. The following flow diagram (Figure 5.1.1) summarizes the structure of the price build-up which has been adopted.

A. <u>c.i.f. price of petroleum products</u>

The exercise began with the border price of petroleum products. The actual c.i.f. price at two major ports of landing viz. Bombay and Madras, was available for a few petroleum products such as MS, FO and SKO [7]. For other products viz. HSD & ATF the c.i.f. price was calculated by taking an arithmetic average on the basis of the total value and quantity of imports of individual products in 1987-88[3]. In case of LPG, the c.i.f. price was taken from [5]

The unit c.i.f. price, hence obtained, was on weight basis (Rs/kg). This was converted to volume basis (Rs/lit) by taking the specific gravity of different petroleum products [3]. To this was added a 40% foreign exchange premium to reflect the scarcity of foreign exchange.

[redacted]gure 5.1.1:Efficient price build-up of petroleum products



The calculation of c.i.f. prices of selected petroleum products are presented in the Table 5.1.1 below:

Table 5.1.1 : Estimation of c.i.f. price of selected petroleum products

Product	Quantity of imports in 1987-88 ('000tonnes)	Value of imports in 1987-88 (Rs crores)	Unit value (Rs/kg)	Unit value (Rs/lit)	c.i.f. price (inclusive of a 40% foreign exchange premium) (Rs /lit)
1. MS					
- at Bombay			2.73	1.91	2.68
- at Madras			2.70	1.89	2.65
2. HSD	1329	297.57	2.24	1.85	2.59
3. ATF	39	9.64	2.47	1.72	2.41
4. LPG					4.[illegible]7[1]
5. FO					
- at Bombay			1.22	1.14	1.59
- at Madras			1.42	1.32	1.85
6. SKO					
- at Bombay			2.56	1.19	2.79
- at Madras			2.50	1.95	2.73

[1] refers to Rs /kg.
Sources:
1, 5, 6 : [7]
2, 3 : [3]
4 : [5]

B. Handling of products at ports

For estimating the cost of unloading and handling at the ports, LPG was treated in a slightly different way as compared to other liquid fuels. In order to increase the level of LPG imports, the terminal facilities at some ports would need to be augmented [5]. Thus, the capital expenditure together with the running and maintenance costs were considered. However, for other products, we considered the case where existing port handling capacities were adequate to cater to marginal increases in imports. Any capital expenditure incurred was thus only for replacing the existing capital. Hence, only the operation and maintenance costs of receiving and unloading the products were considered.

Port handling of LPG: These costs have been obtained for two cases

1) increasing LPG import handling facilities at existing LPG ports of Bombay and Vishakhapatnam.
2) setting up new facilities for handling LPG import parcels at other ports i.e. Haldia and Mangalore.

The annualized capital costs plus annual operation and maintenance costs for each of the two cases were obtained from [5]. These are summarized in Table 5.1.2 below.

Table 5.1.2 : Annualized capital costs and O&M costs of LPG Port Facilities	
Case	Annualized cost (Rs/tonne)
Augmentation of port facilities at Bombay & Vishakhapatnam	240.47
Development of facilities at new LPG ports of Haldia & Mangalore	377.95
Source : [5]	

Port handling of other liquid products

The operation and maintenance costs considered for receiving and handling the imports were taken from [5] and pertain to SKO only. For analytical purposes these costs, after adjusting for differences in specific gravities, were assumed to be the same for other petroleum products also. These running costs, which include wharfage, berth hire charges, tug charges, port dues, pilotage and transshipment charges, vary from one port to another. Table 5.1.3 below contains data on the operating charges at different ports of India.

Table 5.1.3 : Costs of handling petroleum products at ports					
	Operating charges (Rs /kl)				
	MS	HSD	ATF	FO	SKO
Bombay	8.25	9.73	9.14	10.99	9.16
Vishakhapatnam and Madras[1]	39.52	46.61	43.79	52.66	43.90
Mangalore & Haldia	42.84	55.52	47.66	57.08	47.58

Source : [5]
[1] Personal communication with the Indian Ports Association, New Delhi, revealed that the costs of port handling are more or less the same for the ports lying on the same side of the coastline. Thus, in the present analysis, these costs at Madras are taken to be the same as that at Vishakhapatnam.

C. Long distance transportation of petroleum products

The economic costs of transportation, as included in the build-up of the efficient price, were obtained from [4] and reflect the real resource cost of moving and handling the fuel by different modes such as rail, road, pipeline and sea. Furthermore, the cost of supplying the fuel to its consumers was computed for various distance slabs and for different combinations of source/origin and destination. The

place of origin includes selected ports such as Bombay, Madras, Vishakhapatnam, Haldia and Mangalore. From Bombay, Madras and Haldia, the imported fuels are transported to Delhi, Kanpur and Calcutta.

From the port of Vishakhapatnam, the product moved to Calcutta and Madras and from Mangalore the city of destination was Madras.

For the purpose of analysis, the movement by rail refers to a train running on a broad gauge track, using diesel and in the plains (BGDL-BL-Plains). Similarly, transportation by highways was calculated for a typical traffic situation viz. national highway transportation having a double lane and in the plains (NHDL-DL-Plains).

In order to correct the distortions arising out of market imperfections, administered prices and externalities inherent in the prevailing freight rates, the financial cost data were appropriately corrected to reflect the economic cost of various components[4]. For this, the guidelines established by the Project Appraisal Division of the Planning Commission were adopted. Suitable adjustments were made by taking into account the premium on foreign exchange, border prices for traded/tradeable commodities, appropriate social rate of discount and real resource cost of the inputs. The details of transportation costs are given in Annexures 5.1.1 to 5.1.4.

D. Cost of bottling of LPG

For estimating the cost of LPG bottling, two scenarios were considered.

1) a small bottling plant of 5000 tonnes per annum (tpa) capacity is erected at the city gate to cater to the needs of the people living in the town/city.

2) a big bottling plant of 44,000 tpa capacity is erected which satisfies the LPG demand of households located within a radius of about 400 kilometers.

The capital costs of four 5000 tpa capacity bottling plants set up by BPCL at Tuticorin, Lucknow, Hissar and Kurda were considered. These costs were averaged to arrive at the normative capital cost of a plant with similar capacity. The cost of land, land development, civil works, filling equipment, electrical and other equipment, pipeline network, storage, railway siding etc. were also included. The average annualized capital and operation & maintenance costs, as estimated in [5], are presented in Table 5.1.4.

It is reported by the IOC that the capital cost of a 44,000 tpa capacity LPG bottling plant is Rs 300 million if it is fed by road, and Rs 400 million if it is fed by rail. Considering these cost estimates and the annual running cost of the plant, the annualized total cost per tonne of bottling capacity installed was calculated. These estimates are also presented in Table 5.1.4 below.

Table 5.1.4 : Cost of a typical small & large LPG bottling plant	
Type of plant	Annualized cost (Rs/tpa)
Small 5000 tpa bottling plant installed at city gate	1215.44
Large 44,000 tpa bottling plant - road fed - rail fed	 1263.79 1671.63
Source : [5]	

E. Cost of tankage/storage of other petroleum products

As per the norms established by the oil industry, the total storage capacity at depots, ports or at various tap-off points along a product pipeline should provide a stock of 45 days of consumption. This implies that for every kilolitre increment in demand the tankage capacity is to be increased by 123.3 litres (45x1000/365).

Several tankage facilities are under construction at present. Their capital costs vary considerably from one location to another owing to differences in the cost of land, land requirements, availability of infrastructural facilities at the site, tankage capacity etc. Here, an average capital cost of Rs 3000/kl was considered [5]. The annualized capital cost plus O&M costs are presented in Table 5.1.5.

Table 5.1.5 : Cost of storage of selected petroleum products at depots located at the city gate					
	MS	HSD	ATF	FO	SKO
Annualized capital cost plus annual O&M cost Rs/kl of consumption	68.02	72.23	67.86	81.61	68.02
Source : [5]					

F. Distribution costs

Distribution of LPG

Bottled LPG is delivered to the consumers by private LPG distributors. The oil marketing companies supply the distributors with cylinders, which they usually store in their godowns. Besides a godown, the distributor usually owns an office, delivery vehicles, telephone and some furniture.

The investment incurred by an LPG distributor and the number of refills serviced per month vary from one town/city to another. The capital investment varies owing to differences in the cost of land for godowns and office, their construction, furniture and fittings etc.

The number of workers employed and the ownership of delivery vehicles depends upon the number of refills serviced per month. It is observed from the data available from the oil industry that LPG sales per household vary across towns/cities. The number of refills required per annum per household depends on factors such as the monthly household income, its food and cooking habits etc. Taking all these factors into account, the distribution cost per household on an annual basis was worked out [5]. These costs are summarized in Table 5.1.6 below for selected towns/cities.

Table 5.1.6 : LPG distributor costs

Town/city	Distribution cost (Rs/customer/annum)
Bombay	18.23
Delhi/Madras	19.26
Calcutta	13.74
Kanpur	11.39

Source : [5]

Distribution of MS/HSD & ATF

Beyond the point of tankage/storage, bulk of the sales of MS and HSD are routed through retail pump outlets (RPOs) and consumer pumps. The movement of the MS/HSD from storage depot to RPOs usually takes place by road. The delivery charges from storage depots to RPOs were estimated by assuming a distance of 25 kms between the two. Since the tanker/lorry will unload itself at the RPO and makes a return journey to the depot, the total transportation cost was calculated for a distance of 50 km. The cost of intracity transportation was taken from [4] for a haulage of 50 kms.

The retailers of these products are compensated through a commission on the sale of these products which is intended to cover their expenses on heads such as establishment expenses, overheads and a reasonable rate of return for operating the RPOs. The rates of commission on MS/HSD have been revised on several occasions in the past owing to escalating costs. The current rates of commission for MS and HSD, which came into force in February 1986 and prevailed during 1987-88 are presented below. These are classified by slabs of annual sales.

Table 5.1.7 : Rates of dealers commission for motor spirit and HSD		
Annual sales (kls)	Motor spirit (Rs/kl)	HSD (Rs/kl)
0-360	151	84
361-600	113	63
601-1080	99	45
above 1080	79	39
Source : [3]		

The sale of ATF/AV gas for aircrafts are routed through Air Field Stations (AFSs). From the point of storage, we considered the case where ATF was delivered to the AFS by road in tankers/lorries from the depots. In this case also distance and the delivery charges were taken to be the same as for MS and HSD.

In so far as the cost of establishment and operation of these stations is concerned, the OCRC (1984) had recommended a uniform rate of Rs 68/kl for large capacity AFS with a sophisticated fuel hydrant system [2]. This was based on the industry projection of future operating costs of AFS. In our analysis, we considered the same unit distribution cost of ATF through the AFSs.

Distribution of SKO/LDO

Unlike MS/HSD, SKO/LDO are not delivered products. From the point of storage, agents/stockists (wholesalers) take the delivery and deliver it to authorized dealers or sub-agents (retailers) licensed for this purpose by the state government. As per the recommendations of the OCRC (1984), the rates of commission allowed for agents/stockists and retailers (excluding remuneration) were fixed at Rs 30.30/kl and Rs 39.70/kl respectively. These rates of commission were likely to be in force in 1987-88 and were intended to cover all costs borne by agents/stockists and retailers but exclude octroi, sales tax and delivery costs from the depots of storage/tankage of the product. A detailed break up of these costs is tabulated below.

Table 5.1.8 : Distribution cost of SKO/LDO		
	Distribution cost (Rs/kl)	
	Agents/stockists	Retailers
Remuneration	9.70	9.70
Barrel depreciation allowance	4.00	8.00
Leakage	3.00	6.00
Handling expenses	4.00	4.00
Other expenses	9.60	12.00
Total	30.30	39.70
Source : [2]		

G. Marginal cost of supply of major petroleum products

The delivered costs of petroleum products were arrived at by adding the different components of costs discussed in the foregoing sections. These have been calculated for typical combinations of source and destination as well as for varying distance slabs (except for transportation by pipelines). These estimates are presented in Annexures 5.1.1 to 5.1.4, while sample calculations for each of the product are shown below.

Price build-up of major petroleum products as estimated from Bomba-' to Delhi

Price build-up of Motor spirit (Bombay to Delhi)			
	Unit		Source
1. c.i.f. price at Bombay port[1]	(Rs/lit)	2.68	[7]
2. Port handling costs	(Rs/lit)	0.008	[5]
3. Transportation costs (a) by rail - BGDL-BL-Plains[2] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 299.66 0.21	 [5] [4]
(b) by road - NHDL-Plains[3] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 832.31 0.58	 [5] [4]
(c) by pipeline (i) distance (ii) transportation cost	 (kms) (Rs/lit) (Rs/lit)	 1186.00[4] 454 21 0.32	 [5] [5]
4. Annual capital and O&M cost of storage/tankage at depots	(Rs/lit)	0.068	[5]
5. Retailer's costs (RPOs) (a) Cost of intracity transport[5] (b) Annual capital and O&M[6] cost of infrastructure	 (Rs/lit) (Rs/lit)	 0.036 0.15	 [3]
Total cost - by rail - by road - by pipeline	(Rs/lit) 3.15 3.53 3.26		
Note: Explanations for superscripts in this and the following tables are provided at the end of this section. PS : A conversion factor of 1.427 kl/tonne is used for motor spirit.			

Price build-up of ATF (Bombay to Delhi)			
	Unit		**Source**
1. c.i.f. price at Bombay port[1]	**(Rs/lit)**	**2.41**	**[3]**
2. Port handling costs	**(Rs/lit)**	**0.009**	**[5]**
3. Transportation costs **(a) by rail - BGDL-BL-Plains**[2] **(i) distance** **(ii) transportation cost**	 **(kms)** **(Rs/tonne)** **(Rs/lit)**	 **1388.00** **299.66** **0.23**	 **[5]** **[4]**
(b) by road - NHDL-Plains[3] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 832.31 0.65	 [5] [4]
(c) by pipeline (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1186.00[4] 454.21 0.35	[1] [5] [5]
4. Annual capital and O&M cost of storage/tankage at depots	(Rs/lit)	0.068	[5]
5. Retailer's costs (AFSs) (a) Cost of intracity transport[5] (b) Annual capital and O&M[7] cost of infrastructure	 (Rs/lit) (Rs/lit)	 0.040 0.068	 [2]
Total cost - by rail - by road - by pipeline	(Rs/lit) 2.83 3.24 2.95		
PS : A conversion factor of 1.288 kl/tonne is used for ATF.			

Price build up of High Speed Diesel (from Bombay to Delhi)			
	Unit		Source
1. c.i.f. price at Bombay port[1]	(Rs/lit)	2.59	[3]
2. Port handling costs	(Rs/lit)	0.0097	[5]
3. Transportation costs (a) by rail - BGDL-BL-Plains[2] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 299.66 0.25	 [5] [4]
(b) by road - NHDL-Plains[3] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 832.11 0.69	 [5] [4]
(c) by pipeline (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1186.00[4] 454.21 0.37	 [5] [5]
4. Annual capital and O&M cost of storage/tankage at depots	(Rs/lit)	0.072	[5]
5. Retailer's costs (RPOs) (a) Cost of intracity transport[5] (b) Annual capital and O&M[6] cost of infrastructure	 (Rs/lit) (Rs/lit)	 0.0429 0.084	 [3]
Total cost - by rail - by road - by pipeline	(Rs/lit) 3.05 3.49 3.17		
PS : A conversion factor of 1.21 kl/tonne is used for HSD.			

Price build up of Furnace Oil (from Bombay to Delhi)

		Unit	Source
1. c.i.f. price at Bombay port[1]	(Rs/lit)	1.60	[7]
2. Port handling costs	(Rs/lit)	0.011	[5]
3. Transportation costs (a) by rail - BGDL-BL-Plains[2] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 299.66 0.28	 [5] [4]
(b) by road - NHDL-Plains[3] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 832.11 0.78	 [5] [4]
(c) by pipeline (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1186.00[4] 454.21 0.42	 [5] [5]
4. Annual capital and O&M cost of storage/tankage at depots	(Rs/lit)	0.082	[5]
5. Retailer's costs (a) Cost of intracity transport[5] (b) Annual capital and O&M[4] cost of infrastructure	 (Rs/lit) (Rs/lit)	 0.048	 [4] [3]
Total cost - by rail - by road - by pipeline	(Rs/lit) 2.02 2.52 2.16		
PS : A conversion factor of 1.071 kl/tonne is used for FO.			

Price build up of Kerosene (from Bombay to Delhi)			
	Unit		Source
1. c.i.f. price at Bombay port[1]	(Rs/lit)	2.79	[7]
2. Port handling costs	(Rs/lit)	0.009	[5]
3. Transportation costs (a) by rail - BGDL-BL-Plains[2] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 299.66 0.233	
(b) by road - NHDL-Plains[3] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1388.00 832.31 0.65	 [5] [4]
(c) by pipeline (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/lit)	 1186 00[4] 454.21 0.353	 [5] [5]
4. Annual capital and O&M cost of storage/tankage at depots	(Rs/lit)	0.068	[5]
5. Wholesaler's costs (a) Cost of intracity transport[5] (b) Annual capital and O&M[8] cost of infrastructure	 (Rs/lit) (Rs/lit)	 0.040 0.030	 [4] [3]
6. Retailer's cost (a) Cost of intracity transport (b) Annual capital and O&M[5] cost of infrastructure[9]	 (Rs/lit) (Rs/lit)	 0.023 0.039	 [4] [3]
Total cost by rail by road by pipeline	(Rs/lit) 3 23 3 65 3.35		
PS : A conversion factor of 1.285 kl/tonne is used for SKO.			

Price build up of LPG (from Bombay to Delhi)			
When LPG is bottled in a 5000 tpa capacity plant at the city gate			
	Unit		Source
1. c.i.f. price at Bombay port[1]	(Rs/kg) (Rs/HH/annum)[10]	4.07 693.70	[5]
2. Port handling costs[11]	(Rs/kg) (Rs/HH/annum)	0.24 40.98	[5]
3. Transportation costs (a) by rail - BGDL-BL-Plains[2] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/kg) (Rs/HH/annum)	 1388.00 299.66 0.30 51.06	 [5] [4]
(b) by road - NHDL-Plains[3] (i) distance (ii) transportation cost	 (kms) (Rs/tonne) (Rs/kg) (Rs/HH/annum)	 1388.00 832.31 0.83 141.83	 [5] [4]
4. Annual capital and O&M cost of bottling[12]	(Rs/kg) (Rs/HH/annum)	1.22 207.11	[5]
5. Cost of transporting cylinders from bottling plant and distributors godowns[13]	(Rs/HH/annum)	2.92	
6 Annualized capital and O&M cost of cylinder & valve regulator	(Rs/HH/annum)	83.18 7.19	[5]
7. Annualized capital and O&M cost of distributor	(Rs/HH/annum)	19.26	
Total cost - by rail - by road - by rail - by road	 (Rs/HH/annum) (Rs/HH/annum) (Rs/kg) (Rs/kg)	 1105.40 1196.16 6.49 7.02	

5.1.4 Market price of petroleum products

In order to compare the efficient supply price with the prevailing market price, the retail selling price of these products were considered. These prices, as charged in major towns/cities of India, were obtained from [3]. The market prices of selected petroleum products, effective from 1.4.1987 are compiled in Annexure 5.1.5.

Notes

(1) Inclusive of a 40% premium on foreign exchange outflows.

(2) Broad gauge - diesel traction-block load in plains. The economic costs of rail transportation were scaled up from 1984-85 prices to 1987-88 prices by using the price index computed from GDP at current and constant prices originating in the "railways" sub-sector of the economy.

(3) National highway - double lane in plains. The economic costs of road transport were scaled up from 1984-85 prices to 1987-88 prices by using the price index calculated from GDP (at both current and constant prices) originating in the sub-sector "transportation by other means", .

(4) Refers to a new pipeline from Bombay to Mathura (1040 kms); and existing pipeline from Mathura to Delhi (146 kms).

(5) This value was derived by taking the distance between storage depots and the point of sale to consumers as 50 kms (to and fro) and the cost of transportation by road from [4] which is Rs 44.75/tonne for a 50 kms distance slab.

(6) Refers to the upper limit (for the lowest slab of sales volume) of the dealer's commission as taken from [3] on the sale of MS and HSD.

(7) Refers to the compensation recommended by the OCRC (1984) [2] for the costs incurred by the AFSs with a sophisticated fuel hydrant system.

(8) Refers to the cost of delivering SKO from storage depots to agents/stockists (wholesalers) and to the retailers of SKO as given in [3].

(9) Refers to the rates of commission recommended by the OCRC (1984) [2] for wholesalers and retailers of SKO and are intended to cover all the costs borne by them

(10) Number of refills per year in
(a) Bombay, Delhi and Madras - 12
(b) Calcutta and Kanpur - 8.5
(c) Other cities and towns - 7

The consumption of LPG is a function of factors such as the average household income, food habits and cooking preferences.

(11) Refers to the annualized capital and O&M costs of augmenting the port facilities at Bombay. The development of new LPG import handling facilities were reported to be under construction at Haldia and Mangalore ports and hence considered likewise.

(12) Refers to the annual capital and running costs of a 5000 tpa capacity LPG bottling plant at the city gate.

(13) Refers to the movement of LPG cylinders by trucks/ lorries. The cylinder was taken to be transported from the bottling plant located at the city gate to the distributor's godowns for a distance of about 20 kms (to and fro).

5.2 Coal

5.2.1 Introduction

The efficient price of coal was estimated on the basis of its average incremental cost (AIC) of production. Ideally, the AIC method estimates the Long Run Marginal Cost (LRMC) by discounting (at the social rate of interest) all incremental (capital and operating) costs that would be incurred in future to provide the estimated additional amount of coal produced over a specified period, and dividing it by the discounted value of incremental output over that period [10]. Here, an attempt was made to estimate, not the LRMC in the strict sense i.e. the cost of producing one additional unit of the product in the long run, but rather the average cost of producing that additional unit in the long run.

The cost of extracting coal is related to various geological parameters of the coal fields such as depth, seam thickness, inclination, gassiness etc. which in turn, determine the technology to be deployed for extracting coal. In the present analysis, the alternative technologies have been classified as opencast (OC) and underground (UG) with varying degrees of mechanisation. The OC mines were further subdivided into two - those using shovel-dumper (SD) and those using a combination of dragline (DL) with SD. The UG mines were again categorised as those using mechanised bord and pillar (BP) and those using long wall (LW) method of extracting coal. The base year of the analysis was taken as 1987-88.

Both the capital as well as operating costs were taken into account for computing the AIC of producing coal for each of the four categories of mines. Furthermore, the cost of processing of raw coal viz. washing of coking coal and manufacture of soft coke were also added to the cost of production.

The cost of transportation of coal constitutes a significant portion of its delivered price. The real resource or economic cost of transporting coal from the mine-head to its point of consumption was also included in the price build-up. These economic costs relate to different modes of moving coal over varying distances.

5.2.2 Data base

Owing to paucity of data the analysis was restricted to the companies of Coal India Limited (CIL).

The data on unit operating cost of coal on heads such as salaries & wages, stores, power, transport etc. for 1987- 88 were obtained from CMPDIL, Ranchi. This information was available on mine-wise basis for a sample of 329 mines spread over 5 coal companies of the CIL. A break up of these mines, both company-wise & technology-wise, is given in Table 5.2.1 below :

Table 5.2.1 : Company-wise and technology-wise classification of coal mines			
Name of company	Total	Number of mines	
		Opencast	Underground
BCCL	118	45	73
CCL	53	29	24
NCL	5	5	-
SECL	51	14	37
WCL	102	39	63
TOTAL	329	139	197

Along with the information on operating costs, data on other operating variables such as the average grade of coal produced, number of persons employed, OMS, aggregate sales and average selling price of coal were also obtained.

The investment cost data were provided by the CIL, New Delhi. These data cover a set of 334 mining projects undertaken over 17 years from 1973 to 1990. The information was classified according to the status of the project i.e. ongoing(O) or completed(C) and is further subdivided into OC and UG mining schemes. It is stressed that these data refer to both new and reorganization and expansion schemes. The details furnished pertain to variables such as the date of project sanction, scheduled and actual date of completion, sanctioned and actual investment expenditure and ultimate production capacity of the mine after project completion.

A comprehensive break up of these investment projects by type of company, project status and technology deployed is given in Table 5.2.2 below.

Table 5.2.2 : A detailed break-up of investment projects							
Name of company	Total	Number of mines					
		Status		Technology			
		O	C	OCSD	OCDL	UGLW	UGBP
BCCL	65	23	42	30	-	2	33
CCL	59	25	34	45	-	-	14
ECL	63	21	42	31	2	4	26
NCL	11	5	6	3	8	-	-
SECL	76	33	43	16	9	2	49
WCL	60	22	38	28	3	-	29

The cost of washing of coking coals was based on the information obtained for two new washeries viz. Madhuband for prime coking and Rajrappa for medium coking coals. These data were collected from a study carried out by TERI [9] and originally obtained from the detailed project reports of these washeries. The data pertain to both capital and running costs of washing. The cost of manufacture of softcoke, deploying the SSF technology, was obtained from the project profile of one such SSF plant [2]. This consists of information on the actual process of manufacture of softcoke, raw coal input norms, capital investment and primary inputs required for manufacturing i.e., labour, power and water.

The cost of transportation of coal was taken from the study conducted by RITES [8]. This study relates to different modes of transporting coal such as road, rail, coastal shipping etc., over varying lengths of distance for alternative traffic situations. The distances to be travelled for specific combinations of origin and destination were obtained from a study of the Planning Commission [7].

5.2.3 Sample selection

There were several limitations observed in the above collected data. To overcome the data constraints the size of the sample chosen for analysis was a fairly restricted one.

Firstly, the information on investment costs for all the mining schemes referred to both ongoing and completed projects. A closer observation of the data revealed that actual capital expenditure of the scheme was invariably different from the sanctioned capital. Therefore, the sample of mines chosen for analyses pertained to completed projects only, for which data on actual investment at the time of completion was available. The first approach of regression analysis was based on these completed projects only. Also, since very few observations were present in the OCDL and UGLW group of mines, the regression analysis was restricted to the OCSD and UGBP group of mines.

Secondly, it was observed that the date of project sanction did not refer to the original date of sanction of the project. A number of projects are submitted for procuring additional finances during the period of construction. Thus, the date of sanction pertained to the time when the latest revised project report was sanctioned and additional funds released for its completion.

Thirdly, although the data on incremental investment for each of the mining schemes was available the information on capacity additions therefrom was not available. The available data gave the ultimate capacity of production and not the incremental capacity additions which can be ascribed to the incremental investment expenditure.

This necessitated that the analysis be confined only to the new coal mining schemes where the date of sanction referred to the original date when the project was sanctioned for the first time. Also, the value of ultimate capacity would be synonymous to the incremental one resulting entirely from the investment expenditure.

Therefore, with a view to compute economically efficient prices, according to the alternative approach, the sample chosen contained only completed and new mining projects. All the investment projects which were either incomplete or referred to reorganization/expansion schemes were excluded from the sample.

As a result, the number of mines shortlisted in each technology group are summarized in Table 5.2.3.

Table 5.2.3 : The sample size

Type of technology	Number of mines
OCDL	4
OCSD	18
UGLW	2
UGBP	9
Total sample size	33

5.2.4 Methodology

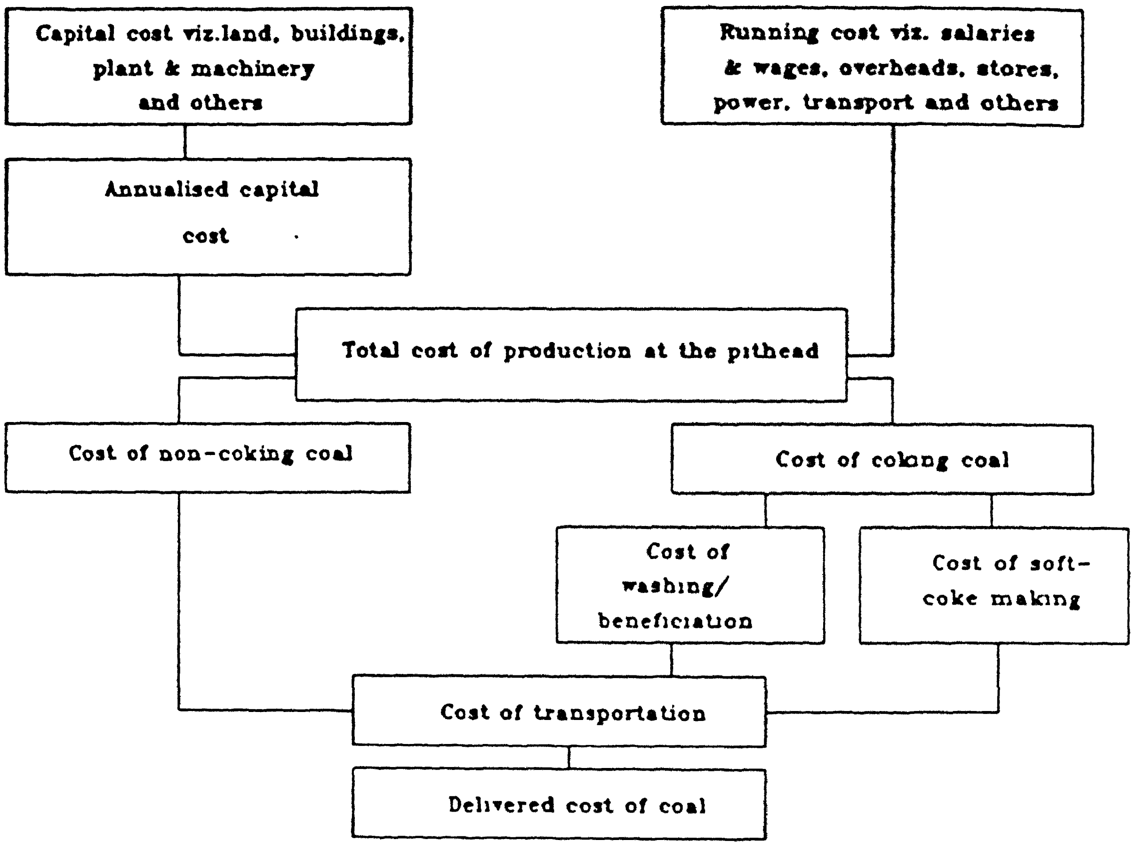
The cost of production from any given coal reserve depends upon its geological features and the techno-economic norms of the technology deployed

In the present analysis, the entire sample of mines has been classified under four groups. They are:

1) Open cast - shovel & dumper
2) Open cast - combination of dragline with shovel and dumper
3) Underground - longwall
4) Underground - bord and pillar

The production costs have been evolved for both coking coal (CC) and non-coking coal (NCC), wherever possible, for each of the above technology groups. The cost estimates were worked out for the categories mentioned in Figure 5.2.1 given below.

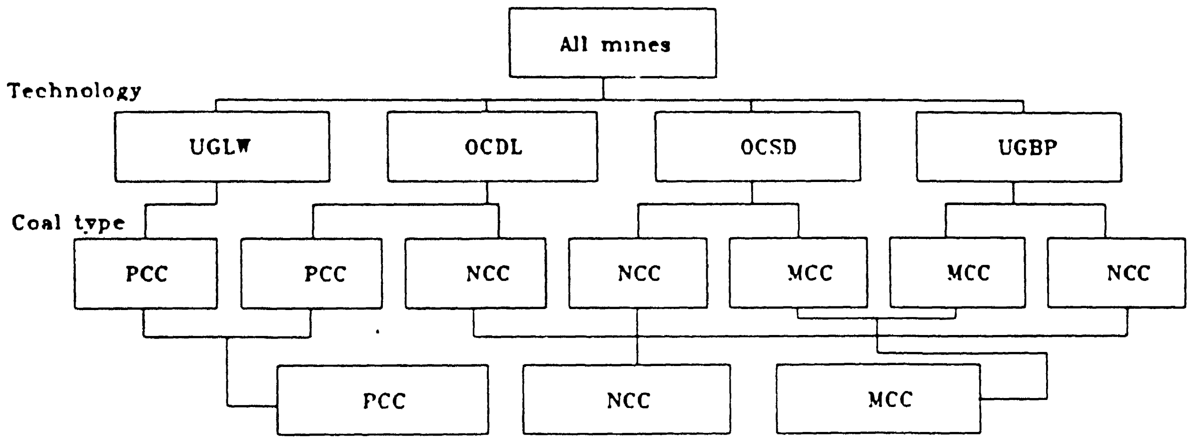
Figure 5.2.2 : Efficient price build-up of coal



It is widely accepted that while the cost of coal production is a function of the geo-mining conditions and the method of mining is not related to the quality of coal being extracted. Therefore, for analytical purposes the efficient prices were calculated on the basis of the average normative costs pertaining to average grade of coals being produced, which is Grade D in case of NCC and W-IV in case of CC. Furthermore, economic cost of production of prime coking coal (PCC) and medium coking coal (MCC) have also been worked out separately on the basis of a restricted sample of three mines in each category.

The broad structure which was adopted for computing the technology-wise average incremental cost of coal production is summarized in Figure 5.2.2.

Figure 5.2.1: Broad categories for which MSC of coal is evolved



The overall cost of production consists of components such as salaries and wages, stores, transportation and overheads as well as the annualised capital cost (ACC). For analytical purposes, the first four components of cost were taken to be the same as reported by individual coal mines. However depreciation and interest, as reported in the data, were purely accounting values and did not represent the actual economic cost of capital employed. In order to correct this distortion, it was decided to arrive at an investment norm for each of the above-mentioned technologies. It is on the basis of this normative investment that the ACC (inclusive of interest) was computed.

To calculate the normative investment cost for each of the mining methods first a regression approach was adopted. This, however, failed to give any meaningful results. Therefore, an alternative approach was used.

The regression approach

To begin with, in order to compute the normative investment cost a Linear Regression Analysis based on the method of Ordinary Least Squares was adopted. Here, an attempt was made to quantify and assess the relationship between investment cost and some key parameters characterizing the investment scheme viz. the date of sanction, date of completion, gestation period, size of capacity etc. As is explained in Annexure 5.2.1 the regression approach did not give any meaningful results for calculating real depreciation and interest cost of capital. This necessitated the adoption of an alternative approach in this respect.

Alternative approach

In the absence of any clear relationship emerging between investment and some key parameters, an alternative approach was adopted. Here the cost of capital per unit of capacity, for each of the mining methods, was estimated as an average of the investment costs incurred on the projects included in that category. A discussion of this approach is presented below.

A. Cost of production

1. Normative investment cost :

In the alternative approach, normative investment was calculated as a simple arithmetic average of specific investment cost of the mining schemes included in each of the technology groups. Since investments did not delineate a clear trend over the years for which data were available, (see Annexure 5.2.1), investment norms were evolved by considering projects which get completed either in 1987-88 or after it.

As a first step, the total investment expenditure was divided by the ultimate installed capacity to arrive at investment per unit of capacity for each of the mining projects.

Next, for each technology type, a simple mean of these observations was calculated and used as representative of the investment required per unit of installed capacity. The results of this exercise are summarized in Table 5.2.4 below and a detailed account is given in Annexure 5.2.2.

Table 5.2.4 : Normative investment costs of capacity in the coal sector

Type of technology	Average investment cost in 1987-88 (Rs crores/mty of installed capacity)
OCDL	32.76
OCSD	24.98
UGBP	29.80
UGLW & OCDL-PCC	80.49
OCSD & UGBP-MCC	30.10

The total normative investment expenditure for individual mining projects was worked out as a product of unit investment norm, (computed for each group of mining technology) and the corresponding targetted installed capacity at the time of completion of the project (see Annexure 5.2.3). This total investment of the project was used for calculating the ACC.

2. Annualised capital cost

Most of industrial assets decrease in utility and value with use and with the passage of time. This process is called consumption of capital or depreciation. The process of depreciation results in a reduction of value of capital investment. To provide for the proper charging of capital cost of an enterprise, these are annualised and added on to the operating expenses of the enterprise [1].

In our analysis, the entire stock of capital has been broadly classified into four categories viz. land, building (both offices and residences), plant and machinery and others (i.e. furniture and fixture, railway aiding, vehicles, roads, water supply etc.). In making our calculation of AIC of producing coal, depreciation was estimated on the basis of annual capital recovery cost for each type of capital stock. The allowance for depreciation was made on annual basis and depended upon the life of each equipment and the social rate of interest chosen for analysis.

Although the data collected from CIL gave information on the total investment expenditure for different mining projects there was no information on the distribution of this investment over major heads of capital. In the absence of this information total investment was apportioned over different heads by using certain percentage norms. These percentages were derived from the detailed project reports of a sample of 10 mining projects of CIL for which information was available (see Annexure 5.2.4). The typical life considered for each element of capital was also obtained from the above-mentioned sample. This limited

information indicated that, with the exception of land, the life of all other types of capital stock is generally taken to be the same for preparing the project reports. In case of land, the life considered was an average of the lives reported in the sample. The distribution of investment and the life of each type of investment expenditure are summarized below in Table 5.2.5 and detailed calculations are presented in Annexure 5.2.4.

Table 5.2.5 : Typical distribution of investment and operating life of major categories of capital stock in coal production

	Distribution of total investment (%)	Operating life (years)
Land	2.0	60
Buildings	6.5	58
Plant & Machinery	81.5	20
Others	10.0	20

Furthermore, a 12% annual social rate of interest was used.

On the basis of the above-mentioned factors viz. a) distribution of total investment, b) operating life of capital (OL) and c) social rate of interest (i), the capital consumption allowance was calculated by annualising the value of total investment expenditure.

For each of the mining projects, the capital consumption allowance for different components of capital stock was estimated as a product of the investment and its capital recovery factor (CRF)[1]. Thereupon, these were aggregated for the four categories of capital expenditure to arrive at the value of total consumption of capital per annum. Lastly, the depreciation cost per unit of output was worked out by dividing total consumption of capital by the typical output of a mine after it has reached a stage of stability in its flow of production. Here, an 85% level of capacity utilisation[2] was assumed for the OCDL, UGSD and UGBP groups of mines while a value of 50% was used for the UGLW group of mines. The cost of

[1]
$$CRF = \frac{i(1+i)^{OL}}{[(1+i)^{OL}-1]}$$

[2]A value of 85 per cent capacity utilisation is generally assumed in the preparation of coal mining project reports. A lower fact of 50 per cent capacity utilisation for UGLW is used because this technology is functioning poorly in India.

interest on capital outlays was implicit in the formula used for calculating the CRF. Detailed calculations regarding these are given in Annexure 5.2.3.

3. Runnin.. costs

The operating costs of coal production comprise expenditure on salaries and wages, overheads, stores and spares, power and transportation charges. These costs were taken as reported by the individual mines of CIL and pertain to the year 1987-88. A detailed account of these costs is presented in Annexure 5.2.3.

4. Total cost of production

The total cost of production is calculated by aggregating the ACC and running costs each of the mining schemes. The representative average cost of production, for each technology was computed as a simple arithmetic mean of the production costs estimated for the mines included in each category. These estimated costs of production are tabulated below.

Table 5.2.6 : Estimated average cost of production of coal (Rs/tonne)

Type of technology	Average cost of production in 1987-88
OCDL - NCC	156.52
OCSD - NCC - CC	157.13 237.74
UGBP - NCC UGLW - PCC	260.09
OCDL OCSD - MCC	513.27
UGBP	289.67

A perusal of the above results indicates that in general the cost of production is higher for the underground as compared to the opencast methods of mining.

B. Beneficiation of coking coal

A major proportion of coking coal reserves of India are high in ash content. This deems it necessary to reduce the ash content to acceptable limits by suitable beneficiation before supplying them to the steel plants. Hence, the cost of coal washing/beneficiation was worked out and included in the total cost of supply.

A distinction is generally made between washeries which handle prime coking and medium coking coals. In our study, the costs of coal washing were worked out on the basis of information available for two new washeries viz Madhuband (capacity 2.5 mt) and Rajrappa (capacity 3 mt) for handling prime and medium coking coals respectively. These washeries are under construction and are likely to be commissioned between 1991-92 and 1993-94. The costs involved in the construction and running of these washeries were obtained from a study carried out by TERI [9]. Since all data pertain to constant January 1989 prices these were converted to the base year prices of 1987-88 by using appropriate price indices. The type and value of price indices, used for each element of cost, are presented in Tables 5.2.7 and 5.2.8 below.

Table 5.2.7 : Type of price index used for each type capital stock in coal washeries

	Price index used
Land	overall WPI
Buildings	a weighted average of WPI & CPI
Plant and machinery	WPI for machinery
Furniture	overall WPI
Railway siding	a weighted average of WPI & CPI
Vehicles	WI for transport equipment
Development	a weighted average of WPI & CPI
FRP supply	a weighted average of WPI & CPI
Pilot R&D schemmes	a weighted average of WPI & CPI

Table 5.2.8 : Value of price indices

	WPI			CPI
	Overall	Machinery	Tranport Equipment	
1970-71	100.0	100.0	100.0	100.0
1987-88	405.4	358.4	413.7	390.8
January 1989	438.1	395.2	493.0	421.1

Source: [3]

The total cost of washing coal was estimated by aggregating the annualized capital and running costs for the two washeries. The ACC of washing were calculated as in the case of coal production. For estimating the ACC the steps adopted were much the same as those used for working out the cost of coal production.

The cost of coal washing was calculated in terms of Rs /tonne of clean coal by assuming a 70% capacity utilisation of washeries in terms of raw coal feed. Furthermore, the washery yields for prime and medium coking coals were taken as the average yield of all washeries in the two categories in 1987-88 [9]. These were estimated to be 62.41% and 50.35% for prime and medium coking coals respectively (see Annexure 5.2.5). The costs of washing, which result from the above calculations are presented in Table 5.2.9 below.

The process of washing produces a by-product in the form of middlings and residues called rejects. Middlings are sold in the market for purposes of power generation and process heating in the industrial sector. Thus, adequate credit was given to the sale of middlings which reduces the net cost of washing coal.

It was observed from the data on yields of coal washing that middlings accounted for nearly 41.50% and 61.85% of clean prime and medium coking coals respectively in the year 1987-88 (Annexure 5.2.5). Assuming that the entire output of middlings was sold at a price of Rs 150/tonne, the net cost of washing was worked out as follows.

Table 5.2.9 : Gross & net costs of washing coal (Rs/tonne of clean coal)

Type of coal	Gross cost	Credit for middlings	Net cost
PCC	173.37	62.25	111.12
MCC	150.20	92.77	57.43

C. Cost of soft coke making

Soft coke, which is produced and marketed in India, is manufactured from coals with some caking properties viz.low grade coking coals. It is used for household cooking as well as for input in brick kilns. The prevalent practice of soft coke making by the "Bhatta method" consists of stacking the steam sized coal in large heaps and allowing it to undergo partial combustion in the presence of air. Thus, a part of the volatile matter present in coal escapes into the atmosphere and a part undergoes combustion. Thereafter, the solid residues are quenched with water.

This, however, is not an efficient process because of two reasons. Firstly, due to lack of control on the process of burning, some pieces of coke get overburnt or underburnt, leading to emissions of smoke

while burning it in domestic chulhas. Secondly, a large amount of unburnt hydrocarbons are vented out into the atmosphere causing serious air pollution. To do away with this unhygienic and old practice, CIL has recently developed a mechanized process for the production of soft coke which also produces tar as a by-product. A uniform sized soft coke is produced by this newly evolved method termed as the Special Smokeless Fuel (SSF).

The production of SSF deploys a shallow depth continuous vertical retort for achieving the devolatilisation of the raw coal. The retorts are kept in operation for 24 hours a day throughout the year. The plant capacity is either 50 tpd or 100 tpd. The type of coal used in the SSF plant is essentially low grade coking coal with some caking properties. Normally, the following properties are indicative of the needed quality.

Ash	-	above 42%
Volatile matter	-	above 12%
Caking index	-	above 8-12%

The requirement of raw coal for an SSF plant, inclusive of screening losses, are given below.

50 tonnes of SSF per day - 83 tonnes
100 tonnes of SSF per day - 168 tonnes

The other primary inputs required are labour, power and water.

The cost of soft coke making using W-IV grade of coking coal was estimated on the basis of the information available from CIL (Annexure 5.2.3). The cost estimates obtained are given in the Table 5.2.9 below and detailed calculations are presented in Annexure 5.2 6.

D. Long distance transportation of coal

The foregoing sections contain a discussion of the methodology used and the estimates obtained for the AIC of coal production and processing at the pithead. In order to arrive at the delivered cost of coal, there is need to take into account the cost of transportation from the pithead and its distribution amongst the consumers. In India, steel plants are the primary consumers of coking coal while power utilities and railways account for a bulk of the consumption of non-coking coal.

The problem of transportation arises mainly in case of noncoking coal due to a wider geographical scatter of the power plants. Since most of the steel plants are located relatively closer to the major mining areas, the transportation system is geared either directly from the mine to the plant or from the mine to the washery and finally to the plant.

Railways are the predominant mode of transporting coal, although road movement is gradually becoming important. The other modes of moving coal are coastal shipping, ropeway and conveyer belt.

In the present analysis, the economic cost of long distance movement of coal was worked out in a fashion analogous to the one used for petroleum products. These costs were estimated for specific origin-destination combinations as well as by varying slabs of distance. In the first case, the place of origin refers to a cluster of mines with a relatively small geographical spread and located in the major coal producing regions of India. Each cluster was localized at one point which was considered to be a point of origin. A group of 13 such clusters were taken as points of coal supply. Similarly, the place of destination refers to major cities of Delhi, Bombay, Calcutta and Madras. Here, the distances to be travelled were considered for two modes of transportation i.e. railways and coastal shipping (wherever such a link exists in the transportation chain). In the second case, the transportation costs were estimated for a series of distance slabs classified by modes of transportation i.e. rail, road and coastal shipping. These estimates are presented in Annexure 5.2.7.

E. Losses in transit

It was reported by CIL that there occur some losses in coal during transportation from the pithead to consumers end. These losses are largely on account of the loss of moisture content in coals and leakages in the wagon. The survey results of a power plant revealed that these technical losses (excluding losses due to pilferage etc.) amounted to about 2-3% of the total coal loaded at the pithead. Thus, theoretically these should be taken into account while estimating the LRMC of coal. However, due to non-availability of more information, this factor has not been taken into account in the present analysis.

F. Estimated marginal cost of supply of coal and soft coke

The estimates of cost of supply of coal and soft coke, obtained for specific origin and destination combinations and by slabs of distance, are presented in Annexure 5.2.7.

5.2.5 Comparison of efficient price with the prevailing market price

As is explained in chapter 4, government administers the pithead price of coal while leaving the price paid by the consumers largely uncontrolled. To arrive at the delivered market price of coal - both coking and noncoking - the structure outlined in Figure 4.2.1 (Chapter 4) was adopted.

Market price of noncoking coal

The market price of noncoking coal was worked out for the same origin - destination combinations as well as distance slabs as its efficient price.

In case of noncoking coal, for the purpose of comparison, price of grade D, the average grade of coal produced in 1987-88, was considered. The administered price of this grade is higher for the coal produced in Andhra Pradesh by SCCL vis-a-vis that produced by the companies of CIL.

When prices were estimated for specific origin-destination combinations, this difference in the price of similar grades of coal was duly taken into account.

In estimating prices according to slabs of distance, the average grade of coal i.e. grade D produced by CIL was considered.

Moreover, to the pithead price were added the components of royalty, cesses, sales and excise taxes which are imposed either by the state or central governments. The rates of these financial charges vary across states as well as by type and grade of coal. These rates, as prevalent in 1987-88, are enlisted in Annexure 5.2.8. A detailed account of these calculations is given in Annexure 5.2.9.

The market price of soft coke was worked out by taking the existing minemouth price of Rs 175 per tonne [4]. In case of soft coke also the cost of transportation was added for specific origin-destination combinations and by distance slabs.

In case of both non-coking coal and soft coke, the average freight rates charged by the Indian Railways in 1987-88 for carrying coal to the power plants and for other purposes were considered [6].

Market price of coking coal

To compare the estimated marginal cost of supply of coking coal to steel plants with its market delivered price, the grade of coal considered was W-IV. To the pithead price of coal were added the cost of washing, transportation and levies such as royalty, cesses, sales and excise taxes imposed by the central and state governments. The cost of transportation was computed on the basis of average freight rates charged by Indian railways as specified in the foregoing section. The prescribed rates of the levies are as given in Annexure 5.2.8. A detailed account of these prices for coking coal is also given in Annexure 5.2.9.

5.3 Electricity

5.3.1 Methodology for marginal cost calculation

The economic price of electricity should be determined on the basis of long run marginal cost of supplying electricity for different end-uses. Prices based on historical costs are inadequate as signaling devices and the appropriate signals (i.e. prices) should be related to the marginal costs of meeting additional consumption. Also, prices based on marginal costs lead to optimum resource allocation, as they emphasize the costs incurred (or saved) by every consumption decision at the margin.

Two broad components of marginal costs of generating and supplying electricity are: (a) capacity cost (b) variable cost. The users during the peak periods, who are the main cause of capacity additions, should bear full responsibility for the capacity costs, as well as fuel, operating and maintenance cost. Whereas the off-peak consumers should pay only the fuel cost.

Marginal capacity costs are the investment costs of generation and transmission and distribution facilities associated with supplying an additional unit of electricity. The LRMC of the electricity system has to be based on a long-term generation and related investment plan. Every load increment has a different LRMC, based on the cost structure of the long term investment plan (investment plan should be optimal) required to meet the load increment in question. LRMC is therefore dependent on the forecast of load increment and the capacity expansion plan which usually ranges between 10 to 20 years.

Having arrived at a long-term investment plan for capacity additions, LRMC of generation capacity (long run average incremental cost may be used interchangeably with LRMC) was calculated using the following equation:

$$LRMC = \frac{\sum_{t=1}^{n} \frac{I_t + (M_t - M_{t-1})}{(1+r)^t}}{\sum_{t=1}^{n} \frac{(D_t - D_{t-1})}{(1+r)^t}}$$

where,

I_t = annualized investment in year 't'
M_t = fixed operating cost in year 't' for the utility
D_t = demand in period 't'
r = discount rate
n = number of years considered

The marginal cost of transmitting and distributing the power generated at different voltage levels was estimated next, in a similar manner. The capacity cost of supplying power at different voltage levels was calculated as follows:

$$LRAIC(i) = \frac{LRAIC(i-1)}{1-LF(i,i-1)} + CAP(i,i-1) \text{ for } i = 2 \ldots V$$

where,

LRAIC (i)	=	incremental capacity cost at voltage level i
LF (i,i-1)	=	loss factor for transmitting power between voltage levels i and (i - 1)
CAP (i,i - 1)	=	marginal cost of transmission capacity between voltage levels i and (i - 1)
V	=	number of voltage levels before supply reaches the consumer who is supplied at the lowest voltage

Marginal energy costs are the fuel and operating costs of providing an additional unit of electricity. Marginal energy cost estimates were made for peak and off-peak use separately. The LRMC of peak period energy will be the running cost of the machines to be used last in the merit order to meet incremental peak demand, adjusted by the appropriate peak loss factor at each voltage level. On the other hand, the LRMC of off-peak energy would usually be the running costs of the least efficient base load plants used during this period.

5.3.2 From costs to tariffs

The translation of the LRMC at different voltage levels to tariffs in respect of different consumer categories requires information on consumption patterns and load profiles for each category. Also, data relating to contribution from different consumer categories to the system peak and off-peak periods was required. In view of non-availability of such data with the state electricity boards, contribution from different consumer categories during different times of the day has been estimated on the basis of a sample survey carried out for them.

Capacity costs (at each level of supply) were allocated to the system peak hours, on the basis of the maximum demand reached by the consumer category during system peak hours (not on the basis of the customer group's own maximum demand, unless this occurs during system peak hours). All the off-peak energy consumption was charged at the marginal off-peak energy cost and the peak energy consumption was charged at the marginal peak energy cost. The tariff for a particular consumer category was, thus, calculated as follows:

$$\text{TARE}(i) = \frac{[\text{PE}(i) * \text{PER}(i) + \text{OPE}(i) * \text{OPER}(i) + \text{MD}(i) * \text{MDR}(i)]}{[\text{PE}(i) + \text{OPE}(i)]}$$

where for category i,

TARE(i)	=	average energy rate
PE(i) and OPE(i)	=	peak and off-peak energy consumed
PER(i) and OPER(i)	=	peak and off-peak energy rate
MD(i)	=	maximum demand during system peak hours
MDR(i)	=	maximum demand rate.

The maximum demand rate is in Rs./kW of demand of the consumer during system peak hours. In order to convert these to actual tariffs, the power factor would have to be taken note of, as given below:

M.D Charge in Rs/kVA/day = {Rs./kW/day}/(Power Factor)

This would indicate that if the consumer has a lower power factor the actual effective demand charge would be higher.

5.3.3 Calculation of marginal cost based tariffs

Long run marginal cost based tariffs have been calculated for five states namely, Haryana, Gujarat, Madhya Pradesh, Maharashtra and Tamil Nadu. The long run marginal costs calculations were based on 1987-88 price level and the period 1988-2000 AD was taken as the planning period. Ideally one would need an optimal plan for each state in order to calculate its marginal cost of generating and supplying electricity. However, the optimization exercises conducted by the Central Electricity Authority are based on the regional approach (i.e., there is a separate optimal plan for each of the regions) which aims at regional optimality. In view of the regional approach there are certain difficulties in estimating LRMC separately for each state, but for lack of any other sources of information the schedule of commissioning of projects in each state were taken as per the information given by CEA. It must be mentioned that the Central sector and other common projects from which the state has a committed share have been considered in the relevant schedules.

A comparison of installed capacity vs. the peak demand to be met (as per 13th Annual Power Survey Report) shows that in 2 or 3 time periods the states will face peaking shortages. A part of this is likely to be met through inter- system exchanges and inter-regional exchanges, depending on the demand and availability at that time. A check of the regional power position for the western region, for which data was readily available, indicated that the regional demand requirements will be met.

Based on the schedule of commissioning of projects for each state, the schedule of investments were worked out. As mentioned earlier all the costs were taken in 1987-88 price level. Costs of all the projects were not available and where they were available the base year was not necessarily 1987-88. To bring all the costs to 1987-88 price level, a price index was calculated for thermal plants, hydro plants and gas turbines separately. The price index was calculated based on the original and revised cost data available for some of the power projects.

Next, the costs at 1987-88 price level were distributed according to the disbursement norms obtained from CEA. These norms are stated in Annexure 5.3.1. In the case of ongoing projects, the data on expenditure upto 31st March, 1988 was collected from CEA and the balance cost was distributed on the basis of disbursement norms.

In order to calculate LRMC of transmission and distribution, the schedule of investment in transmission was drawn on the basis of the Report of the Sub-group on Power Systems: Eighth Plan T & D programme 1990-91 to 1994-95. The report gives the details of all the transmission lines expected to come on line during the VIIIth plan[1]. The costs which were given in 1988-89 price level were converted into 1987-88 price level based on the price index of state domestic product for each state. The total costs in 1987-88 price level were next distributed according to the disbursement norms for the different voltage levels. These norms are given in Annexure 5.3.1.

Trends in the ratio of investment in transmission to investment in generation during the VIIth plan was repeated in the IXth plan to work out the investment schedule in transmission during the IXth plan. Investments in 1988-89 and 1989-90 were calculated using the same ratios as in 1993- 94 and 1994-95 respectively.

Total investment planned for distribution during VIII plan was distributed among the five years as 15% in the firt year, 18% in the second year, 20% in the third year, 22% in the fourth year and 25% in the fifth year. Investments in distribution in 1988-89, 1989-90 and in the ninth plan were calculated using the ratios of investment in distribution and investment in generation in the eighth plan.

The basic assumptions underlying the LRAIC calculations are spelt out below:

1. A discount rate (r) of 12% was used. This is in accordance with the normal approach followed for economic evaluation of large public investment projects in India.

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[1]A comparison of the investments given in the Sub-group report and investments requirements made by the SEBs show that the estimates carried out by the boards are substantially higher than the Sub-group.

2. In the case of central sector power projects, a part of the total investment (same proportion as the percent share of the state in the installed capacity of central sector project) was considered as the investment required for the SEBs plan.

3. Annual fixed operating cost was assumed to be 2.5% of the capital for thermal projects cost and 1% for hydroelectric projects (this is in accordance with the usual assumption made in appraisals of power projects).

4. In annualising capital investment, life of a hydro-electric project was assumed to be 50 years and that of thermal/gas based power projects was assumed to be 25 years. Life of the transmission and distribution line was also assumed to be 25 years.

5. The demand and energy estimates have been taken from the 13th Annual Power Survey Report.

6. In order to convert the financial costs of capacity addition to economic costs, a conversion factor of 0.80 was used. This is based on the North Madras thermal power project figures, where the economic cost was estimated to be 80% of the original financial estimate after eliminating taxes and other transfer payments. Since separate figures for taxes/duties for T & D investments were not available, the same ratio of economic to financial cost would appear to be reasonable for T & D costs as well.

7. To calculate LRMC of transmission and distribution at different voltage levels it is important to know how much of the simultaneous system peak demand is handled at each voltage level. Since no estimates were available, the percentage of total electricity sold to LT consumers was taken as an approximation for the share of peak demand arising from LT- consumers.

8. Losses at different voltage levels have been obtained in terms of the length of transmission lines, resistance of the lines and total losses. The losses during peak hour are assumed to be 20% more than that during off peak hours.

Marginal peak energy cost is the running cost of the machines to be used last in the merit order. In a system which has a mix of hydro, thermal and gas-based power plants, gas-turbines operating on fuel oil comes last in the merit order. Therefore, marginal peak energy costs in Haryana, Tamil Nadu, Maharashtra and Gujarat were calculated as the running cost of the gas turbines in each of these states respectively. The economic cost of fuel oil for various distance slabs has been taken from Annexure 5.1.1.

Marginal off-peak energy costs are calulated as the running cost of least efficient thermal power plant. Least efficient thermal plants in each of the states were selected on the basis of the specific coal consumption. Thermal plants with highest specific coal consumption were assumed to come up last in the

merit order and their running cost was taken as the marginal off-peak energy cost. Annexure 5.3.2 gives the details of specific coal consumption of thermal power plant.

The MP system has no gas turbines and is a simple hydro-thermal system. For such systems, the marginal peak energy cost is the running cost of the least efficient thermal plant, since this would be used at the margin to meet the peak demand, after the hydro option is used up. For off-peak marginal energy cost, the thermal stations were ranked in the order of specific coal consumption and the fuel cost of the plant that came on at the margin was taken as the off- peak marginal energy cost. The economic cost of coal was available on the basis of technology used to produce coal. In the case of power plants which were linked to Singrauli mines the economic cost of coal produced by OCDL technology was taken. In case of power plants linked to Dornakal, the economic cost was taken as the weighted average cost of coal produced by UGBP technology and OCSD technology (assuming 75% of the coal produced in Dornakal is by UGBP technology and 25% is produced by OCSD technology). For all other coal mines, weighted average cost of coal was calculated assuming 65% of coal is produced from OCSD technology and 35% from UGBP technology. The economic cost thus, works out to be Rs. 156.52/tonne for Singrauli, Rs. 244.35/tonne in the case of coal produced in Dorkanal and Rs. 193.16/tonne for all other mines.

Next, transportation costs were added to the cost of coal at pit head. The data on coal linkage was used to calculate the average distance travelled by the coal to reach the power station. Economic costs of transporation of coal as given in the RITES report, have been taken.

For estimating the costs (capacity as well as energy) at different voltage levels (EHT&HT and LT) it is essential to take into account the losses at respective voltage levels. Since, the loss figures were not available for different voltage levels we have calculated them on the basis of the assumption that currents flowing through the different transmission lines are proportional to the transformation ratio of different voltage levels. The losses at different voltage levels have, thus, been obtained in terms of the length of the transmission lines, resistances of the lines and total loss. The equations used to calculate the losses at different voltage levels are given in Annexure 5.3.3.

The LRMC based tariffs were calculated for five major categories: domestic, commercial, LT-industries, agriculture and HT-industries. These tariffs were calculated without any consideration of deviation due to social and/or on financial objectives. The calculations were based on sample surveys conducted by TERI in all the five states to establish the consumption pattern of the major consumer categories during different times of the day. The data on hourly loads was collected through meter readings recorded at the consumers' premises for two consecutive days.

5.3.4 Haryana State Electricity Board

Marginal capacity cost

The schedule of commissioning of projects and the schedule of investments for HSEB are given in Annexure 5.3.4 and 5.3.5 respectively. Annexure 5.3.6 gives the details of calculations of marginal cost of generation and Annexure 5.3.7 gives the details of the calculations of marginal cost of transmission and distribution for HSEB system. The marginal capacity cost of generation (economic) at busbar works out to be Rs. 1586.48/kW/year and the marginal capacity cost of transmission and distribution at EHT and HT is Rs. 104.76/kW/year and at LT is Rs. 247.00/kW/year.

Marginal peak energy cost

Marginal peak energy cost was estimated assuming that gas turbines would be used for peaking purposes. Cost of generating one unit of electricity at Dadri gas turbines is calculated as follows.

Economic price of fuel oil (assuming fuel is transported from Bombay port to Delhi)	=	Rs. 2.214/lit
Specific gravity of fuel oil	=	Rs. 0.92
Calorific value	=	9600 kcal/kg
Heat rate for gas turbine	=	2907 kcal/kWh
Energy cost	=	[(2.214/0.92)*(2907/9600)]
	=	73 paise/kWh

Marginal off-peak energy cost

To calculate marginal off-peak energy cost, cost of generation per kWh of electricity of the least efficient thermal plant in the state - Panipat, is calculated as follows:

Economic cost of coal	=	Rs. 193.16/tonne
Average distance travelled by coal	=	1180 km
Transportation cost	=	Rs. 0.22/kg
Total cost of coal	=	Rs. 0.413/kg
Specific coal consumption	=	Rs. 0.93 kg/kWh (Panipat TPS)
Energy cost	=	Rs. 0.38/kWh

Economic LRMC at different voltage levels

Capacity costs and cost of energy sold at different voltage levels is given in Table 5.3.1. For estimating the costs at different voltage levels, the loss factors assumed are 4.96% and 16.54% at EHT & HT an LT respectively.

Table 5.3.1 : Economic LRMC at different voltage levels for HSEB

Voltage level	Capacity cost (Rs/kW)	Energy cost (paise/kWh)	
		peak	off-peak
Busbar	1586.48	73	38
EHT & HT	1774.04	78	40
LT	2372.89	97	48

LRMC based tariffs

Table 5.3.2 gives details of the long run marginal cost based tariffs calculations for some of the major consumer categories. The calculations are based on sample surveys conducted by TERI with the assistance of HSEB staff.

Table 5.3.2 : Tariff calculations for major consumer categories in HSEB (in 1987-88 prices)

	Domestic	Commercial	LT-industries	Agriculture	HT-industries
Peak energy (kWh)	0.59	0.63	5.56	2.53	657.84
Pekak energy rate (Rs/kWh)	0.97	0.97	0.97	0.97	0.78
Off-peak energy (kWh)	1.11	2.13	17.07	4.57	1197 96
Off-peak energy rate (kWh)	0.48	0.48	0.48	0.48	0.40
Maximum demand (kW)	0.11	0.23	2.44	0.38	97.25
Capacity cost (Rs/kW)	6.50	6.50	6.50	6.50	4.86
Marginal cost based tariff (Rs/kWh)	1.07	1.14	1.30	1.00	0.79

5.3.5 Gujarat State Electricity Board

Marginal capacity cost

The schedule of commissioning of projects and the schedule of investments for GEB are given in Annexure 5.3.8 and 5.3.9 respectively. Annexure 5.3.10 gives the details of calculations of marginal cost of generation and Annexure 5.3.11 gives the details of calculations of marginal cost of transmission and distribution for the GEB system. The marginal capacity cost of generation at busbar for the GEB system is Rs. 1634.12/kW/year, and the marginal capacity cost of transmission and distribution at EHT & HT and LT is Rs. 383.39/kW/year and Rs. 335.88/kW/year respectively. It is assumed that in the GEB system, EHT & HT handles 100% and LT handles 59% of the simultaneous system peak demand.

Marginal peak energy cost

Cost of generating one unit of electricity at Vatwa gas turbine is calculated as follows:

Economic price of fuel oil (assuming fuel oil is transported from Bombay port)	=	Rs. 2.03/lit
Specific gravity of fuel oil	=	0.92
Calorific value of fuel oil	=	9600 kcal/kg
Heat rate of gas turbine	=	2907 kcal/kWh
Energy cost	=	[(2.03/0.92)*(2907/9600)]
	=	67 paise/kWh

Marginal off-peak energy cost

Cost of generating one unit of electricity at Wanakbori thermal plant is:

Economic cost of coal	=	Rs. 193.16/tonne
Average distance travelled by coal	=	1072 km
Transportation cost	=	Rs. 0.22/kg
Total cost of coal	=	Rs. 0.413/kg
Specific coal consumption	=	Rs. 0.63 kg/kWh
Energy cost	=	Rs. 0.26/kWh

Economic LRMC at different voltage levels

Capacity cost and cost of energy sold at different voltage levels is given in Table 5.3.3. For estimating the costs at different voltage levels, 4.69% and 14.81% losses are assumed at EHT & HT and LT respectively.

Table 5.3.3 : Economic LRMC at different voltage levels for GEB			
Voltage level	Capacity cost (Rs/kW)	Energy cost (paise/kWh)	
		peak	off-peak
Busbar	1634.12	67	26
EHT & HT	2097.92	77	27
LT	2798.52	94	32

LRMC based tariffs

Table 5.3.4 gives details of the long run marginal cost based tariff calculations for some of the major consumer categories. The calculations are based on sample surveys conducted by TERI with the assistance of the GEB staff.

Table 5.3.4 : Tariff calculations for major consumer categories in GEB (in 1987-88 prices)

	Domestic	Commercial	LT-industries	Agriculture	HT-industries
Peak energy (kWh)	0.42	0.68	10.06	10 48	3264.59
Peak energy rate (Rs/kWh)	0.94	0.94	0.94	0 94	0.77
Off-peak energy (kWh)	1.08	2.04	34.07	25 54	10536.45
Off-peak energy rate (kWh)	0.32	0.32	0.32	0.32	0 27
Maximum demand (kW)	0.14	0.27	2.76	2.55	659.73
Capacity cost (Rs/kW)	7.67	7.67	7.67	7 67	5.75
Marginal cost based tariff (Rs/kWh)	1.16	1 22	0.92	0 97	0.65

5.3.6 Maharashtra State Electricity Board

Marginal capacity cost

The schedule of commissioning of projects and the schedule of investments for the MSEB are given in Annexure 5.3.12 and 5.3.13 respectively. Annexure 5.3.14 gives the details of calculations of marginal cost of generation and Annexure 5.3.15 gives the details of calculation of marginal capacity cost of transmission and distribution for the MSEB system. Marginal capacity cost of generation at bus bar for the MSEB system is Rs. 1607.84/kW/year; and the marginal capacity cost of transmission and distribution at EHT & HT and LT is Rs. 301.35/kW/year and Rs. 233.27/kW/year respectively. It is assumed that in the MSEB system EHT & HT handles 100% and LT handles 54% of the simultaneous system peak demand.

Marginal peak energy cost

Cost of generating one unit of electricity at Dhabol gas turbine is calculated as follows :

Economic price of fuel oil	= Rs. 1.99/lit
Specific grvity of fuel oil	= 0.92
Calorific value	= 9600 kcal/kg
Heat rate of gas turbine	= 2907 kcal/kWh
Energy cost	= [(1.99/0.92) * (2907/9600)]
	= 65 paise/kWh

Marginal off-peak energy cost

Cost of generating one unit of electricity at Khaperkhera thermal power plant is

Economic price of coal	= Rs. 193.16/tonne
Transportation cost	= Rs. 0.066/kg
Specific coal consumption	= 1.09 kg/kWh
Energy cost	= Rs. 0.28/kWh

Economic LRMC at different voltage levels

Capacity cost and cost of energy sold at different voltage levels for the MSEB is given in Table 5.3.5. For estimating costs at different voltage levels, it is assumed that losses at EHT & HT and LT level are 4.27% and 10.13% respectively.

Table 5.3.5 : Economic LRMC at different voltage levels for MSEB

Voltage level	Capacity cost (Rs/kW)	Energy cost (paise/kWh)	
		Peak	Off-peak
Bus bar	1607.84	65	28
EHT & HT	1980.91	69	29
LT	2437.46	78	33

LRMC based tariffs

Table 5.3.6 gives details of the long run marginal cost based tariff calculations for some of the major consumer categories. The calculations are based on sample surveys conducted by TERI with the assistance of MSEB officials.

Table 5.3.6 : Tariff calculations for major consumer categories in MSEB (in 1987-88 prices).

	Domestic	Commercial	LT-industries	Agriculture	HT-industries
Peak energy (kWh)	0.44	1.26	12.06	2.89	2770.33
Peak energy rate (Rs/kWh)	0.78	0.78	0.78	0.78	0.69
Off Peak energy (kWh)	1.01	2.35	30.52	7.96	8002.33
Off Peak energy rate (Rs/kWh)	0.33	0.33	0.33	0.33	0.29
Maximum demand (kW)	0.112	0.315	2.653	0.733	496.71
Capacity Cost (Rs/kW)	6.68	6.68	6.68	6.68	5.43
Marginal Cost based tariff (Rs/kWh)	0.98	1.07	0.87	0.90	0.64

5.3.8 Madhya Pradesh Electricity Board

Marginal Capacity Cost

The schedule of commissioning of projects and the schedule of investments for MPEB are given in Annexure 5.3.16 and Annexure 5.3.17 respectively. Annexure 5.3.18 gives the details of calculations of marginal capacity cost of generation and the details of calculations of marginal capacity cost of transmission and distribution is given in Annexure 5.3.19 . The marginal capacity cost of generation at busbar is Rs 1467.25/kW/Year and the marginal capacity cost of transmission and distribution at EHT & HT and LT is Rs 280.51/kW/Year and Rs 642.03/kW/Year respectively. It is assumed that in the MPEB system, EHT and HT handles 100% and LT handles 42% of the simultaneous system peak demand.

Marginal peak energy cost

The MP system is a simple hydro-thermal system and has no gas turbines. The marginal peak energy cost of such a system is the running cost of the least efficient thermal plant. The cost of generating one unit of electricity at Korba Thermal Power Plant is calculated as follows :

Economic price of coal	= Rs.193.16/tonne.
Transportation cost	= Rs.0.066/kg
Specific coal consumption	= 0.94 kg/kWh.
Energy cost	= Rs.0.24/kWh.

Marginal off peak energy cost

The MPEB system, as on 31st March 1989, had a total installed capacity of 3087.5 MW, comprising 2697.5 MW of thermal capacity and 390 MW of hydro capacity. The average off-peak demand for the MPEB system during the month of January 1989 was 1800 MW. It is assumed that 100 MW of the total off peak demand of 1800 MW would be met from hydro plants, and the rest of the hydro capacity would be used during peak hours. If all the thermal power plants in the MPEB system are ranked in increasing order of specific coal consumption, one finds that Amarkantak thermal power station will start generating at the margin during off-peak hours. The cost of generating one unit of electricity at Amarkantak thermal power station is calculated as follows :

Economic price of coal	= Rs.193.16/tonne.
Transportation cost	= Rs.0.066/kg
Specific coal consumption	= 0.74 kg/kWh.
Energy Cost	= Rs.0.19/kWh.

Economic LRMC at different voltage levels

Capacity cost and cost of energy sold at different voltage levels is given in Table 5.3.7. For estimating the costs at different voltage levels, losses at EHT&HT and LT are assumed to be 6.30% and 12.70% respectively.

Table 5.3.7 : Economic LRMC at different voltage levels for MPEB

Voltage Cost	Capacity (Rs/Kw)	Energy cost level (Paise/kWh)	
		Peak	Off Peak
Busbar	1467.25	24	19
EHT&HT	1847.21	26	20
LT	2757.97	31	23

LRMC based tariffs

The details of calculations of LRMC based tariffs for some of the major consumer categories are given in Table 5.3.8. The calculations are based on the sample surveys conducted by TERI with the assistance of the MSEB officials.

Table 5.3.8 : Tariff calculations for major consumer categories in MPEB (in 1987-88 prices)	Domestic	Commercial	LT-industries	Agriculture	HT-industries
Peak energy (kWh)	1.11	0.70	3.91	n.a.	n.a.
Peak energy rate (Rs/kWh)	0.31	0.31	0.31	0.31	0.26
Off Peak energy (kWh)	1.70	2.10	13.37	n.a.	n.a.
Off Peak energy rate (Rs/kWh)	0.23	0.23	0.23	0.23	0.20
Maximum demand (kW)	0.28	0.30	1.92	n.a.	n.a.
Capacity Cost (Rs/kw)	7.56	7.56	7.56	7.90	5.06
Marginal Cost based tariff (Rs/kWh)	1.02	1.06	1.09	-	-

5.3.8 Tamil Nadu Electricity Board

Marginal Capacity Cost

The schedule of commissioning of projects and the schedule of investments for the TNEB system are given in Annexures 5.3.20 and 5.3.21 respectively. Annexure 5.3.22 gives the details of calculations of marginal capacity cost of generation and Annexure 5.3.23 gives the details of calculations of marginal capacity cost of transmission and distribution. The marginal capacity cost of generation at busbar for the TNEB system is Rs. 1753.51/kW/Year and marginal capacity cost of transmission and distribution at EHT&HT and LT is Rs. 169.95/kW/Year and Rs. 740.28/kW/Year respectively. It is assumed that in TNEB system EHT & HT handles 100% and LT handles 53% of the simultaneous system peak demand.

Marginal peak energy cost

Cost of generating one unit of electricity at Basin Budge gas turbine is calculated as follows:

Economic Prices of fuel oil	= Rs.1.99/Lit
Specific gravity of fuel oil	= 0.92
Calorific Value of fuel oil	= 9600 kcal/kWh
Heat rate for gas turbine	= 2907 kcal/kg.
Energy Cost [(1.985/0.92)*(2907/9600)]	= 65 paise/kWh.

Marginal off-peak energy cost

Cost of generating one unit of electricity at Ennore thermal power plant is calculated as follows:

Economic price of coal (Ennore gets coal from Dorkanal)	= Rs.244.35/tonne.
Average distance travelled by coal	= 559 km
Transportation cost	= Rs. 0.141/kg
Total cost of coal	= Rs. 0.385/kg
Specific coal consumption	= 0.93 kg/kWh.
Energy Cost	= Rs. 0.36/kWh.

Economic LRMC at different voltage levels

Capacity cost and cost of energy sold at different voltage levels in given in Table 5.3.9. For estimating the costs at different voltage levels, it is assumed that losses at EHT & HT are 4.30% and at LT are 14.20%.

Table 5.3.9 : Economic LRMC at different voltage levels for TNEB

Voltage level	Capacity Cost (Rs/kW)	Energy cost (Paise/kWh)	
		Peak	Off Peak
Busbar	1753.00	65	36
EHT&HT	2001.72	69	38
LT	3073.28	83	44

LRMC based tariffs

Table 5.3.10 gives details of the long run marginal cost based tariff calculations for some of the major consumer categories. The calculations are based on sample surveys conducted by TERI with the assistance of TNEB officials.

Table 5.3.10 : Tariff calculations for major consumer categories in TNEB (in 1987-88 prices).

	Domestic	Commercial	LT-industries	Agriculture	HT-industries
Peak energy (kWh)	0.31	0.60	1.55	2.00	1765.30
Peak energy rate (Rs/kWh)	0.83	0.83	0.83	0.83	0.69
Off Peak energy (kWh)	0.71	1.77	5.62	5.93	5302.24
Off Peak energy rate (Rs/kWh)	0.44	0.44	0.44	0.44	0.38
Maximum demand (kW)	0.08	0.14	0.75	0.55	312.04
Capacity Cost (Rs/kw)	8.42	8.42	8.42	8.42	5.48
Marginal Cost based tariff (Rs/kWh)	1.22	1.04	1.51	1 21	0.70

5.3.9 Comparison of LRMC based tariffs and average revenue realised

A comparison of marginal cost of supply for different consumer categories and the average revenue realised is given in table 5.3.11. The important points that emerge are :

(a) LT commercial consumers pay less than the marginal costs. This is the trend that should be reversed.

(b) Domestic consumers continue to have subsidies. This is one group of consumers where cross-subsidization within the group can be strongly considered by way of suitable block tariffs.

(c) The LT industrial consumers are not subsidised. The marginal difference in GEB could be neutralised.

(d) Agricultural consumers get the maximum subsidies. The trend that has been set up over the period since the early eighties seems almost impossible to reverse. One would have to look at other options, outside the tariff system, to recover costs from this consumer group.

(e) HT consumers pay rates substantially higher than marginal costs by a factor close to 1.6-1.8, except for HSEB and TNEB where the difference is quite small.

Table 5.3.11 : Comparison of LRMC based tariff and average revenue realised (in 1987-88)

(paise/kWh)

	Domestic	Commercial	LT-industries	Agriculture	HT-industries
HSEB	1.07 (0.42)	1.14 (0.82)	1.30 (0.87)	1.00 (0.17)	0.79 (0.98)
MSEB	0.98 (0.47)	1.07 (0.89)	0.87 (0.75)	0.90 (0.09)	0.64 (1.10)
GEB	1.16 (0.68)	1.22 (0.68)	0.92 (1.07)	0.97 (0.22)	0.65 (1.10)
MPEB	1.02 (0.28)	1.06 (1.00)	1.09 (0.87)	n.a. (0.23)	n.a. (0.91)
TNEB	1.22 (0.59)	1.04 (0.96)	1.51 (0.87)	1.21 (0.12)	0.70 (0.87)

Note : Figures in brackets are average revenues realised in 1987-88.

5.4 Natural gas pricing

5.4.1 Introduction

Natural gas is emerging as an important source of energy, primarily to supplement petroleum products whose deficits are predicted to rise in the years ahead.

Natural gas is a versatile compound finding its use as a fuel or feedstock in sectors such as fertilizer, power, petrochemicals, sponge iron, LPG shrinkage, town gas for domestic/commercial use and other sectors (tea estates, brick kilns, boilers in mills etc.). The annual production of natural gas rose from 8.13 BCM in 1985-86 to 15.35 BCM in the terminal year of the Seventh Five Year Plan. According to the production targets of ONGC and OIL, it is expected that the production would rise to a level of 97 BCM in 1994-95.

In the past more than 30% of natural gas produced in India has been flared owing to either lack of investible resources to expand its supply or insufficiency.of downstream facilities for its use. These losses are highly undesirable and can no longer by afforded. In this context, evolving an appreciate pricing policy for natural gas to achieve efficient production and transportation as well as correct signals for its utilisation and sending substitution finds a central place.

5.4.2 Evolution of natural gas pricing

Prior to January 1987 natural gas prices were fixed in an adhoc manner and revised from time to time largely by the gas producing companies. At that juncture, the Government of India appointed a committee to evolve a pricing policy for natural gas. The committee recommended the establishment of natural gas prices in such a manner that there existed some parity between these and the prices of fuel/feedstock which were sought to be replaced by natural gas. Further, with the exception of the fertilizer sector, the prices for other consumers were to vary along the HBJ pipeline to incorporate transportation costs. Owing to the centralized subsidy scheme, a uniform price was suggested for the fertilizer manufacturers. Concessional prices were also recommended for the north-eastern region.

However, the prices finally approved by the Government were based entirely on the cost of production with no distinction made between the price payable by consumers and those paid to producers.

In view of the growing importance of natural gas, it was deemed necessary to consider this pricing structure. Thus another committee, under the chairmanship of Dr. V. Kelkar, was set in March 1989 to look afresh into natural gas pricing. The Kelkar committee addressed the issues pertaining to principles for gas pricing, price structure (uniform pricing vs regional variations, consumer vs producer prices). In this respect, the committee held detailed discussions with the consuming sectors, producing organisations (ONGC, OIL, GAIL) and concerned departments of the government.

The cost of production for gas produced by ONGC was calculated by adopting two alternative approaches - a) financial costs, and b) long-run average incremental costs(LRAIC). These costs were estimated for the year 1988-89, and the results are set out in Table 5.4.1 below.

Table 5.4.1 : LRAIC of natural gas

	Unit	Production	Transportation	Sweetening	Exploration	Total
Sum of PV of annual capital costs	Rs crores	575.15	579.95	347.48	1480.24	
Sum of PV of annual operating cost	Rs crores	294.75	69.01	116.78	-	
Sum of PV of output flow	bcm/year	22.167	21.754	17.729	29.897	
Economic cost	Rs/'000m³	392	298	262	495	1447

Thereafter, the producer prices were compared with the replacement value of gas (as a feedstock or fuel) in the fertilizer and power sectors. The committee argued that the economic value of gas to the consumer and the price charged from them should reflect the benefits that accrue to them. The replacement value of gas was estimated in both financial and economic terms. These results are presented in Table 5.4.2 below.

Table 5.4.2: Replacement value of natural gas in major consuming sectors

Sector	Economic replacement value (Rs/'000 m³)	Financial replacement value (Rs/'000 m³)
Fertilizers		
Case I[1]	2784	2495
Case II[2]	3258	2951
Power		
Case I[3]		
- pithead	1917	1942
- 500 km	2289	2503
- 1000 km	2519	3024
Case II[4]		
- pithead	2196	2199
- 500 km	2567	2760
- 1000 km	2797	3280
Case III[5]	2085	

[1] Gas based and naphtha based fertilizer plants assumed to operate at a same level of 80% capacity utilization.
[2] Gas based power plants assumed to operated at a higher level of 90% of capacity utilization
[3] Both gas based and coal based power stations operate at a PLF of 62.79%.
[4] Gas based power station operate at a higher PLF of 79.91% as compared 62.79 for coal based power stations
~~Source: [2]~~ (5) Natural gas replaces fuel oil in a thermal power

A comparison of the natural gas producer prices with the corresponding economic values show that the latter are much higher than the former owing to additional benefits yielded by natural gas for specific end-uses. Bearing this in mind, it was recommended that the LRAIC and the economic value should be considered as lower and upper bounds respectively and that actual price be set between these two levels.

5.4.3 Efficient price build up of natural gas

In the present analysis, the economic supply price of natural gas is based on its average incremental cost (AIC)[1] which seems best suited to the natural gas technology. The AIC smoothens the indivisibilities in investment expenditure and reflects the general trend of future costs which will have to be incurred as gas consumption increases. The AIC views the costs in the long run and hence gives due attention to the time value of money. This methodology is particularly suitable for the Indian gas sector since it is at an early stage of development and expects a large potential expansion in the demand for gas.

For analytical purposes, the AIC of South Bassein Gas was considered to be an appropriate basis for economic pricing, primarily because:

(1) South Bassein yields free gas and hence avoids the questions related to apportionment of total costs of exploration and development between oil and natural gas.

(2) South Bassein (with the exception of Bombay High) would be one of the largest gas producing fields in India in the years ahead.

(3) the data on the cost of gas production for fields other than South Bassein are rather scarce.

The AIC has been calculated for the following stages of the supply industry i.e.

A. Production

B. Transportation and distribution

C. Compression and retailing

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[1] The AIC is estimated by discounting all incremental costs that will be incurred in future to provide and maintain the estimated amount of gas which will be over a specified time period and dividing it by the discounted volume of incremental output over this time. The stream of expenditures on capital and operations is to correspond to a certain flow of production. The AIC is calculated by using the following formula.

$$\frac{\sum^{T} [I_t + (R_t - R_0)]/(1+i)^t}{\sum^{T} [Q_t - Q_0]/(1-i)^t}$$

I_t = Capital costs in year t

R_t = Operating and maintenance costs in year t

Q_t = Natural gas production in year t associated with the investment

i = Social rate of discount

T = Gestation period for the development project as well as its production life.

A. Cost of production

The cost of production of natural gas from South Bassein also includes the costs associated with the supply of gas from Bassein to Hazira. A brief note on the data, methodology and results is given below.

Investment cost: The capital cost of production, which included investments on exploration, production, sweetening and transportation system, were considered. The temporal phasing of investments incurred on the project was taken into account for each of the above-mentioned four stages of the production process. These data on capital costs were obtained from ONGC [5].

The capital costs were given in current year prices. These were converted to constant 1987-88 prices by using price index of gross capital formation [4].

Operating costs: These included annual expenditure on heads such as manpower, consumables (lubes, corrosion inhibitor, diesel), navigation, repair and maintenance, overheads and vessel hire charges etc. These costs were projected for the entire life of each sub-component of the production system viz. exploration, production etc. with suitable allowance made for the growth in facilities according to a specific operations schedule. All operating costs were given in 1988-89 prices and were converted to constant 1987-88 constant prices by using appropriate price indices.

Production stream: The annual flow of production of gas (including gas equivalent of LPG and NGL) was assessed for the gas field through the transportation and sweetening sub-systems, until the gas reaches the primary distribution point at Hazira.

AIC of production: The AIC of production of natural gas was estimated by using the formula given earlier. The results of the calculation, for each of the stages of supply, are summarized in Table 5.4.3 below.

Table 5.4.3 : Economic cost of supply of natural gas

	Unit	Production	Transportation	Sweetening	Exploration	Total
Sum of PV of annual capital costs	Rs crores	562.14	641.41	500.39	~~1779~~.48	
Sum of PV of annual operating costs	Rs crores	494.62	221.22	237.84		
Sum of PV of output flow	BCM/year	41.41	51.92	~~43.05~~	41.41	
Economic cost	Rs/'000m^3	255.19	166.14	171.47	429.73	~~1022.52~~

B. Transportation costs

Transportation along Hazira-Bijapur-Jagdishpur (HBJ) pipeline : The cost of transmission of gas was estimated for one of the major gas pipeline networks i.e. the HBJ. The pipeline, having a length of 1750 kms, passes through Gujarat, MP, Rajasthan, UP and has been extended to Delhi. GAIL was entrusted with the task of laying this pipeline and hence the cost data were obtained from them.

Data on the cost of the HBJ pipeline pertained to both capital and operating and maintenance expenditure. The investments, beginning in 1984-85 up to 1990-91, were given in current year prices. These were converted to constant 1987 prices by using the price index of gross fixed capital formation [3]. The aggregate operating costs, on an annual basis, were taken as per the detailed feasibility report of the HBJ project. These costs, which were in constant 1982-83 prices, were converted to the base year prices by using a composite consumer price index of industrial workers and urban non-manual employees [1].

The flow of output along the HBJ was estimated by taking a capacity utilization factor of 90%. Using the AIC formula, the economic cost of supply of natural gas along the trunk pipeline was worked out up to the city gate. These costs are set out in Table 5.4.4 below.

Table 5.4.4 : Economic cost of gas transportation along HBJ

	Unit	
Sum of PV of annual capital cost	Rs crores	1724.7
Sum of PV of annual variable costs	Rs crores	674.2
Sum of PV supply	BCM/year	31.91
Length of HBJ pipeline	kms	1750
Economic cost of transportation	Rs/'000 m^3 Rs/km/'000 m^3	751.8 0.43

Intra-city transportation: The cost of distribution of gas within the city was estimated by assuming that gas would be stored at a bigger mother station (where a part of the gas would undergo compression for use in the transport sector). From the mother station bulk of the supply of natural gas to industries would be made directly. In this case, a transportation over 25 kms within the city, was considered. These costs were worked out to be Rs 10.75/'000 m^3 (Rs 0.43/'000 m^3x25).

Table 5.4.5 : Economic cost of supply of natural gas to industry (Rs/'000 m^3)

Cost of gas production	1022.52
Cost of transportation along HBJ pipeline	751.82
Cost of transportation from storage station to consumer	10.75
Total cost of supply	**1785.1**

The cost of supply of compressed natural gas (CNG) for transportation purposes was worked by assuming a mother-daughter station concept, whereby the former would supply gas to four smaller stations by means of cascades (a set of 40 cylinders) carried in a truck.

Cost of compression of natural gas: Compressed natural gas (CNG) is an effective substitute for diesel and gasoline in the transport sector. Natural gas, which is primarily methane (CH_4), is compressed to about 160-200 bars and stored in cylinders mounted on to the vehicles. Hence, for use in the transport sector the cost of compression and fuelling station had to be taken into account. These costs were obtained from a study conducted by the Indira Gandhi Institute of Development Research, Bombay [3]. The cost of establishment of the daughter stations were obtained from GAIL, New Delhi. These costs, as estimated by us, are summarized below.

Table 5.4.6 : Efficient price build-up of CNG

	Unit		
Cost of fuelling station (with a compressor capable of delivering 350 m³/hour)	Rs lakhs	44	
Annual production of CNG (with 80% capacity utilization and 12 hours/day of operation)	mcm	1.225	
		Rs/000 m³	
1. Cost of production of natural gas		1022.52	1259.7
2. Cost of transmission along HBJ		751.82	[illegible]7.14
3. Cost of compression at the mother station			
- variable costs (power, oil, water etc.)		127.89	176.22
- other operating costs (manpower, overheads, operations and maintenance, insurance etc.)		359.02	405.16
- levelized annualised capital cost		527.1	599.3
4. Cost of 4 daughter stations (with retailing facilities)			
- manpower		128.28	153.06
- operating and maintenance		320.81	405.16
- annualised capital cost		412.83	494.41
Total cost of supply of CNG		3650.30	4380.1

Market price of natural gas

The retail selling prices approved by the Government in January 1987 and effective upto 31st March 1989 were as follows. These prices were exclusive of royalty, taxes, duties and other levies imposed by the Government.

(1) Rs 1400/'000 m³ for gas at the landfall points and for onshore gas

(2) Rs 2250/'000 m³ for gas supplied along the HBJ pipeline

(3) Concessional price of gas of Rs 1000/'000 m^3 for the North-Eastern states further subject to a discount up to Rs 500/'000 m^3

(4) A 15% rebate to consumers to whom gas would have been sold on fall back basis

For the purpose of comparison with the economic cost of supply, market price of Rs. 2250/'000 m^3 along the HBJ was considered.

CHAPTER 6

INTEGRATING SOCIAL AND FINANCIAL CONSIDERATIONS IN THE EFFICIENT PRICE STRUCTURE

6.1 Conceptual framework

As is mentioned in chapter 3, a simple matrix framework has been developed that would enable analysis of alternative tax/subsidy regimes on the price signals that are sent out to the consumers as well as of the revenue realizations from each of the energy sub-sector.

The steps in the development of this framework, which is built as a simple spread-sheet model, is the establishment of an energy efficient matrix. The model has as its rows the energy types available for final consumption and as its columns the end-uses for which various energy forms are being consumed. The elements of the matrix represent the efficiency of fuel consumption in specific end-uses. The efficiency numbers are measured in terms of energy consumption per unit of useful output (where useful output could be measured in terms of thermal energy, lumen output, quantity of water pumped, etc.). The product of each of these efficiencies with the corresponding fuel price (economic and market) results in an end-use price matrix that has as its elements the price per unit of useful output for each end-use using alternative fuels. Thus, for example, this would, at a glance, indicate the price of providing a unit of useful cooking energy by using substitute fuels such as LPG, kerosene and soft coke. The efficiency matrix is multiplied by two fuel price matrices - one based on economic prices and the other on market prices. The end-use price matrix based on economic prices gives the actual economic cost of providing a unit of useful energy by using alternative fuels whereas the end-use price matrix based on market prices gives an indication of signals that are being sent to the consumer with respect to the perceived values of these energy sources in specific end-uses.

The next step in this framework is the development of a consumption matrix which has a structure similar to the efficiency matrix but has as its elements the actual consumption of various energy forms in specific end-uses. If detailed information on consumption of various fuels for specific end-uses broken up further by income classes as well as the price elasticities of energy demand of the population in these income classes were available, it would be very simple to look at the social implications of alternative market price regimes. In the absence of this information, all that can be derived are the broad directional changes that are expected in demand if tax/subsidy structures were altered.

The product of the consumption matrix and the price matrix, based on economic and market prices, gives an indication of the desired (or required) vis-a-vis actual realization by sectors of consumption and by fuel type. The difference in these two values would indicate the extent of tax/subsidy accruable to various sectors and fuel types.

6.2 Assumptions

As is brought out in the earlier chapter, prices of coal and petroleum products vary across each state due to differences in the mix of generation capacity as well as load profiles. We have thus a number of alternative efficient price structures that could be utilized for developing this integrated energy price structure. However, if one was to develop these scenarios using all the price-combinations possible then this exercise would become extremely complex and little or no interpretation would be drawn from it. For the purpose of simplicity, without compromising on the quality of the exercise, the following assumptions have been made to arrive at a unique set of prices for each fuel.

(1) In the case of coal, it was generally found that the price variation across open cast technologies was not very significant. Thus a simple average price for open cast technology was taken into account. In the case of underground technologies, only the underground bord and pillar technology was considered as the longwall technology is extremely expensive and inefficient. It has been further assumed that 65% of the production is from open cast technologies and 35% from underground technologies. Thus, the prices over these two technologies have been weighted accordingly to arrive at one cost of production.

(2) In the case of oil, since border prices were used to arrive at the supply cost, we had only one set of prices.

(3) In case of natural gas, the cost of production from South Bassein was considered.

(4) Transport costs have been worked out for var ous distance slabs as is brought out in the previous chapter. Taking into account the average lead distance of coal and oil movement, prices pertaining to a distance slab to 750-1000 kms have been utilized. For prime and medium coking coal being supplied to steel plants, price pertaining to the distance slab of 0-250 kms is considered. For natural gas, the transportation from Hazira to Delhi along the HBJ pipeline was taken. In case of electricity, the prices for various sectors in MSEB were incorporated.

(5) As regards other distribution costs it was found that this component was extremely small and thus average costs were taken.

(6) For electricity the comparison is done on a per kWh basis and the impact of power factor not included. However, it must be pointed out that, while the HT consumers have power factor correction costs, the LT consumers are not penalised for low power factor.

6.3 Results of the price integration

To facilitate an understanding of the results, the various matrices defined above have been disaggregated by sector of consumption. Accordingly, results have also been presented for each sector. Table 6.1 below gives the final set of prices that have been used for the purpose of analysis, both in terms of price per physical unit and price per unit of calorific value.

One aspect that needs to be borne in mind here is that the economic prices as derived above do not, as per definition, include the financial return on costs incurred. This would, to a certain extent, explain the lower economic price of non-coking coal vis-a-vis., its market price. Also the economic price of non-coking coal does not incorporate the higher costs experienced in production taking place by underground longwall technology. If one was to compare the economic and market prices at the pithead then the administered price of non-coking coal is Rs. 212 per tonne which is only about 10% higher than the economic price of Rs. 193 at the pithead in 1987-88. Obviously, the prevailing transportation costs of coal are higher than the economic costs. A comparison of these costs reveals that the economic price of transportation over the distance slab 750-1000 kms is Rs.0.20/TKM against the freight rate of Rs.0.26/TKM charged by the railways. Additionally, the cesses that have been assumed at Rs.88.50/tonne (for Bihar) are over 80% of the component of 'other levies'. Thus the transportation sectors and the state governments benefit through coal transportation and consumption.

Table 6.1: Economic and market prices for a 750-1000 kms distance slab

Fuel	EP	MP	EP	MP
Coal (Rs/Tonne)			Rs/10000 kcal	
NCC	369.36	574.80	0.82	1.28
PCC 0-250 kms	708.91	745.61	1.09	1.15
MCC 0-250 kms	414.18	716.43	0.69	1.19
SC	696.43	433.00	1.39	0.87
Oil(Rs/Tonne)				
FO	2257.59	3320.10	2.17	3.19
HSD	3630.33	4392.30	3.36	4.07
LPG	6430.98	3950.00	5.47	3.36
MS	4415.66	11116.32		3.96
SKO	4038.60	2788.45	3.67	2.53
Natural gas	1785.10	2250.00	2.04	2.57
CNG	3650.30		4.66	
Electricity(Rs/kWh)				
Domestic	0.98	0.47	11.40	5.47
HT Industry	0.64	1.10	7.44	12.79
LT Industry	0.87	0.75	10.12	8.72
Commercial	1.07	0.89	12.44	10.35
Agriculture	0.90	0.09	10.47	1.05

Note: EP - Economic price MP - Market price

<u>Domestic sector</u>

The end-uses that have been considered in this sector include cooking, water heating and lighting. The end-uses of cooking and water heating have been added together since it is extremely difficult to differentiate between fuel consumption for these two activities while the efficiency levels of energy utilization for both the end-uses are almost the same. Lighting energy efficiency has been measured in kilocalories of energy consumption per lumen hour of output whereas that of cooking and water heating have been measured in terms of useful thermal energy output per gross energy input. Table 6.2(a) gives the summary of the results arranged by end-use using both economic prices (EP) and market prices (MP). This table brings out starkly the very high levels of subsidy that are being offered to the domestic sector particularly in the case of electricity and kerosene. LPG, which is considered as the rich man's fuel, is also very highly subsidized.

Table 6.2(a) : Domestic sector analysis

Fuel	Price(Rs/tonne or kWh or '000m3)		Price (Rs/10000 kcals)		Efficiency matrix		End use prices			
	EP	MP	EP	MP	Lighting (kcals/ lhr)	Cooking & W.heating (U kcals/kcal)	EP	MP	EP	MP
							Lighting (Rs /lhr)		Cooking & W. Heating (Rs./ 10000 kcals)	
Soft coke	696 43	433.00	1 39	0.87		0.25	0 00	0 00	5 57	3.46
SKO	4038.60	2788.45	3 67	2.53	2.88	0.45	1.06	0 73	8.16	5 63
LPG	6430.98	3950.00	5.47	3.36		0.65	0.00	0.00	8.42	5.17
Electricity#	0.98	0.47	11 40	5.47	0.17	0.64	0 20	0 09	17 81	8.54
Electricity*	0.98	0.47	11.40	5.47	0.03	0.64	0 04	0.02	17 81	8.54

Note: lhr - lumen hours
U kcals - Useful Kilocalories
#: Electricity use in incandescents
*: Electricity use in fluorescents

Table 6.2(b) : Domestic sector analysis

		Consumption matrix (1987-88)		Realisations (Rs.million)				
Fuel	unit	Lighting	Cooking & W.Heating	Lighting		Cooking &W.Heating		Fuel subsidy
				EP	MP	EP	MP	(Rs.million)
Soft coke	mt		1.44			1002.86	623.52	379.34
SKO	mt	1 61	5.62	6512.30	4496.41	22690.87	15666.91	9039.83
LPG	mt		1.42			9099.84	5589.25	3510.59
Electricity	mkWh	15895		15577.10	7470.65			8106.45
Total				22089.34	11967.02	32793.57	21879.68	21036.21

Note: Realisations based on economic prices refer to desired (or required) levels of realisation

Table 6.2 (b) presents the consumption matrix for this sector as well as total realizations under both the cases and an indication of the extent of subsidy. The total subsidy to the domestic sector for various fuels put together works out close to Rs.2104 crores.

Industrial and commercial sector

The end-uses that have been taken into account in this sector include process heating and lighting. Lighting energy is measured in the same units as for the domestic sector whereas process heating efficiency is measured in terms of the useful thermal energy output. Table 6.3(a) gives a comparison of energy prices per unit of useful output using alternative fuels for these end-uses. It is seen that all the three alternative viz. coal, fuel oil and natural gas consumption in this sector are taxed, whereas the use of electricity is subsidized to the commercial and LT sectors although not to the same extent as in the domestic sector.

Table 6.3(a) : Industrial and commercial sector analysis

Fuel	Price (Rs/tonne or kWh or '000 m3)		Price (Rs/10000 kcals)		Efficiency matrix		End use prices			
					Process heating (Ukcals/kcal)	Lighting (kcals/lhr)	Process heating (Rs/10000 kcal)		Lighting (Rs/'000 lhr)	
	EP	MP	EP	MP			EP	MP	EP	MP
Non coking coal	369 36	574 80	0 82	1.28	0.55		1.49	2.32		
Coking coal	561.55	731.02	0 89	1 17						
Fuel oil	2257 59	3320 00	2 17	3 19	0 75		2 89	4.26		
Natural gas	1785 1	2250	2.04	2 57	0.80		2 55	3 22		
LPG	6430 98	3950 00	5 47	3 36						
Electricity-com*	1 07	0 89	12 44	10 35		0 17			0 21	0 18
Electricity-com#	1 07	0 89	12.44	10.35		0 03			0 04	0.04
Electricity-LT*	0 87	0 75	10.12	8 72		0 17			0.17	0 15
Electricity-LT#	0 87	0.75	10 12	8.72		0.03			0 03	0 03
Electricity-HT*	0 64	1.10	7.44	12.79		0.17			0 13	0 22
Electricity-HT#	0 64	1.10	7.44	12.79		0 03			0.03	0.04

Electricity use in incandescents *. Electricity use in fluorescents

6.3(b) : Industrial and commercial sector analysis

Fuel	UNIT	Consumption matrix				
		Process heating	Ore reduction	LT	HT	Commercial
Non coking	mt	135.89				
Coking coal	mt		26.67			
Fuel oil	mt	3.53				
Natural gas	mcm	380				
LPG	mt					0.271
Electricity-Comm	mkWh					5104
Electricity-HT	mkWh			9528.6		
Electricity-LT	mkWh				42603.4	

Table 6.3(c) : Industrial and commercial sector analysis											
Fuel	Realisations (Rs.million)										
	Process heating		Ore reduction		LT EP	LT MP	HT EP	HT MP	Commercial		Fuel subsidy (Rs million)
	EP	MP	EP	MP					EP	MP	
Non coking	50192.33	78108.89									-27916.56
Coking coal			14976.41	19496.30							-4519.90
Fuel oil	7971.55	11723.27									-3751.72
Natural gas	678.34	855									
LPG									1742.80	1070.45	672.35
Electricity-Comm									5461 28	4542 56	918.72
Electricity-HT					8289 92	7146 48					1143.44
Electricity-LT							27266.15	46863 69			-19597.35
Total	581842 2	90687.4	14976.4	19496.3	8289.9	7146.5	27266.2	46863.7	7204.1	5613.0	-53228.6

Note: Realisations based on economic prices refer to desired (or required) levels of realisation.

On the whole energy supply to the industrial sector is taxed with the total revenue realisations amounting to about Rs 5323 crores.

Transport sector

The transportation sector has been divided into two - the freight transportation sector and the passenger transportation sector. Efficiencies of this sector have been measured in terms of energy requirement for every tonne kilometre or passenger kilometre moved. These have further been differentiated between road and rail transportation [Table 6.4(a)]. The consumption of non-coking coal and diesel are taxed in this sector. There also exists a substantial negative subsidy on the use of electricity for traction purposes. Furthermore, the option of CNG for passenger and freight transportation by road has also been considered. Calculations indicate that CNG is a cheaper option as compared to similar modes for road transportation. Although, rail is the cheapest alternative for both passenger and freight movement. Table 4(b) gives the consumption matrix and realizations in the case of transportation sector. The total negative subsidy to this sector is approximately Rs.4490 crores.

Table 6.4(a): Transport sector analysis										
Fuel	Price (Rs/tonne or kWh or '000 m^3)		Price (Rs/10000 kcal)		Efficiency matrix		End use prices			
	EP	MP	EP	MP	Freight (kcals/TKM)	Passenger (kcals/PKM)	EP	MP	EP	MP
							Rs./'000 TKMS		Rs./'000 PKMS	
Non coking coal	369.36	574.80	0.82	1.28	852.6	294.00	69.98	108.91	24.13	37.55
Motor spirit	4415.66	11116.33	3.96	9.97		348.6			138.05	347.55
HSD-Rail	3630.33	4392 30	3.36	4.07	63.18	41.58	21.24	25.69	13.98	16.91
HSD-Road	3630 33	4392.30	3.36	4.07	449 59	52.5	152.05	182.84	17.65	21.35
Electricity-Rail	0 64	1.10	7.44	12.79	18 92	15.82	14.08	24.20	13.98	20.23
CNG-bus/HCV	3650 3		4.66		197.98	23 38	92 18		10.89	
CNG-car/HCV	3650.3		4.66			250.22			116.50	

Table 6.4(b): Transport sector analysis					
Fuel	Unit	Consumption	Realisations (Rs million)		Fuel subsidy (Rs million)
			EP	MP	
Non coking coal	mt	7.55	2788 67	4339.702	- 1551.03
Motor spirit-Road	mt	2 81	12408 00	31236 9	-18828 8
HSD-Rail	mt	1.38	4991.70	6039 41	-11588 0
HSD-Road	mt	13 83	50218 35	60758 68	
Electricity-Rail	mkWh	28101.00	17984 64	30911.10	-12926.4
Total			88391.36	133285.70	-44894.4
Note: Realisations based on economic prices refer to desired (or required) levels of realisation					

Agricultural sector

The only end-use which has been taken into consideration in this sector is irrigation as the quality of data available for other end-uses is inadequate. Energy efficiency of irrigation has been measured in terms of kilocalories of energy required per m^3 of water pumped out. A comparison is presented in Table 6.5(a) between electric and diesel pumpsets. Again while diesel is taxed, the subsidy provided to the agricultural sector on electricity consumption is extremely high. As against the economic price of Rs 91.90 /thousand m^3 of water pumped, the market price charged to this sector is a mere Rs 9.20/thousand m^3. The total subsidy to this sector, accruable only to electricity consumption, is to the extent of Rs.2702 crores.

Table 6.5(a) : Agricultural sector analysis

Fuel	Price		Price			End use price	
	EP	MP	EP	MP	efficiency	EP	MP
	Rs/tonne (or kWh)		Rs/10000 kcal		kcals/M3	Rs./'000 m3	
HSD	3630.33	4392.30	3.36	4.07	349.65	117.53	142.20
Electricity	0.90	0.09	10.47	1.05	87.80	91.88	9.19

Table 6.5(b) : Agricultural sector analysis

Fuel	UNIT	Consumption		Total realisations (Rs. million)	Fuel Subsidy Rs.million
		EP	MP		
HSD	mt	1.38	5009.86	6061.37	-1051.52
Electricity	mkWh	34652	31186.80	3118.68	28068.12
Total			36196.66	9180.05	27016.60

Note: Realisations based on economic prices refers to desired (or required) levels of realisation

CHAPTER 7
SUMMARY AND CONCLUSIONS

As per our estimation, the energy sectors are revenue generating contributing nearly Rs 5000 crores in 1987-88. A surprising result of this exercise is that coal prices to the consumer are considerably higher than the economic cost of supply. The reasons for this are explained in detail in chapter 6. However, if one was to consider economic and market prices at the pithead then the differential between the two prices is estimated to be much lower.

While it is generally known that electricity is supplied at highly subsidized rates, the sectoral break-up of these subsidy rates is very clearly brought out in Table 6.1. The sector to which the cost of supplying electricity is the highest in terms of electrical losses incurred i.e. agriculture, also enjoys the highest levels of subsidy.

The domestic sector enjoys a very high level of subsidy of Rs. 2104 crores of which approximately 45% is provided in the form of a subsidy on kerosene, roughly 40% in the form of subsidy on electricity and about 7% as a subsidy on LPG.

The domestic sector analysis also brings out clearly the significant price differential between using electricity in fluorescent devices vs. its use in incandescent bulbs. Since this particular end-use also has significant implications on the peak energy demand on a system, the switch over to flourescents is an option which needs to be pursued vigorously.

The end-use price matrix for this sector also brings out the closeness of the prices of kerosene and LPG in meeting cooking energy requirements. Thus, it would seem that the only deterrent to the use of LPG more widely as a cooking fuel would be its availability.

Electricity prices for the domestic consumers should be set in such a way that this category does not have to rely on any subsidy through a suitably designed block tariff. While setting electricity rates it may be necessary to consider price levels of other fuels used within the domestic sector in order to encourage increased use of efficient fuels.

In case of the industrial sector, under both the price regimes, the use of non-coking coal is cheaper than the use of oil and natural gas for process heating purposes despite significantly higher efficiencies of the latter two fuels. Between fuel oil and natural gas, the latter is a slightly cheaper option -both in terms of economic and market prices. This reinforces the findings of several committees which have pointed to the desirability of switching over to coal from fuel oil use in industry. Due to the high per unit market price of non-coking coal as compared to the economic price, the negative subsidy on non-coking coal used in this sector turns out to be very high. This is matched by the negative subsidy on HT electricity consumption which is close to Rs. 1960 crores.

The end-use price matrix of the transportation sector brings out very clearly the trade-offs between road and rail sector for both freight and passenger movement. The costs of rail transportation, in case of freight movement, are roughly a sixth of the costs incurred if one was to move commodities by road (which is diesel based). However, the use of CNG for freight transportation by road is at least

60% cheaper as compared to diesel use. As it happens, there is an increasing trend towards freight transportation by road largely because of the uncertainties associated with rail transportation. These prices give an indication of the opportunity cost of rail transportation and the willingness of consumers to pay for an efficient and reliable transport service.

In the case of passenger transportation, this difference is not as marked. Here, CNG in buses works out to be the cheapest option, almost as low as electricity in rail transportation. This is followed by the use of diesel in railways and public buses in that order. Although the cost of passenger transportation by private modes (such as cars) works out to be much higher as compared to other modes, CNG use in cars is relatively cheaper as compared to petrol. Since diesel is a slightly taxed product there is a negative subsidy to this sector to the extent of Rs. 4490 crores.

The subsidy on the agricultural sector is again very significant at Rs. 2702 crores. The average revenue realised on electricity sales to this sector are a mere 10-11% of the economic price. In the agricultural sector, indications are that there should be a move towards electrification which is the present trend.

A comparison of the ranking of various fuels being consumed in different sectors on the basis of economic price per unit of gross energy and useful energy provided reveals significant changes in the transportation and agricultural sectors. Whereas in the transportation sector non-coking coal use is the cheapest followed by diesel and electricity in gross energy terms, by incorporating efficiencies this ranking changes to electricity, diesel and coal use. Similarly in the agricultural sector although in gross energy terms diesel is cheaper than electricity in useful energy terms electricity is significantly cheaper than diesel use.

In the industrial and domestic sectors, the ranking of fuels remains the same in both gross and useful terms. However, the domestic sector brings forward some interesting results. The closeness of useful economic prices of kerosene and LPG brings out the sensitivity of the relative prices of these two fuels to the efficiencies assumed for kerosene stoves. The efficiency level assumed in this report is 45% against achievable levels of 55% if all consumers were to utilize efficient cook stoves. In the event that this happened the use of kerosene for cooking would turn out to be significantly cheaper than LPG. The use of LPG in industries is also very expensive and a comparison across sectors shows that LPG use in the domestic sector is cheaper than in the industrial sector. An argument that may be used in favour of LPG is the fact that we have increasing amounts of natural gas available thereby making it an attractive substitute for kerosene which is imported in large quantities.

Another interesting finding in this context is that soft coke costs are the cheapest both in gross and useful energy terms. An in-depth analysis should be carried out to find out the reasons for its non-utilization. It may also be worthwhile to consider diverting some of the present subsidy on LPG to further subsidize soft coke. The SSF technology of soft coke production removes one of the major drawbacks associated with the use of this fuel viz. the emission of smoke.

The integrated pricing framework that has been developed as a part of this project allows a great deal of flexibility not only in studying the impacts of changes in the tax/subsidy structure on end-use prices and an indication of the directional changes in demand as a result, but in integrating

new developments in energy producing technologies and their impact on the long run marginal costs of supplying various fuel forms. This study also highlights the need for developing a detailed demand side structure that would allow the interface between the pricing framework and demand side impacts.

While a price structure based on forward looking long run marginal cost of supply in the case of non-tradeables and border prices in the case of tradeables, taking into account inter-fuel substitution possibilities, has several benefits, one can foresee major problems in implementing such a structure.

The first major problem, as is brought out in earlier chapters in this report, relates to the fact that energy prices, as they are presently set, are done so by different organizations with little or no consideration for likely impacts on demands for other fuels. A major challenge here would be the establishment of an institution that would be capable of establishing energy prices in an integrated framework and also be in a position to implement this price structure. Electricity being on the concurrent list, would need special consideration. One could think in terms of an institution like a Utilities Commission with quasi-judicial powers to set efficient energy price levels for various fuels in various regions. These efficient prices would be constrained by administered prices in other sectors of the economy. Another obstacle to the implementation of such a structure would be the inertia in moving to more efficient prices not only on the part of the supply organizations, but also on the part of the consumers who would have to pay much higher prices for the energy that they are consuming. It may, therefore, be desirable to think in terms of allowing for a transition period over which the inefficient prices in force just now could move to the efficient prices along with a simultaneous move towards increased efficiency in operations.

Another problem associated with the implementation of the price structure is the ability of various public sector organizations to recover their dues. Thus, for example the state governments direct the state electricity boards to provide subsidies to the agricultural sector which the state governments are supposed to make good to the extent that the SEBs are unable to recover it by means of higher tariffs to other consumers. However, since the state governments themselves have limited funds for a variety of reasons, the state electricity boards are unable to recover the cost of subsidy incurring heavy losses and thereby not being able to honour their payments. In order to ensure an optimal working of this entire system one would also have to device mechanisms by which the dues from one sub-sector to the other sub-sectors are settled in a reasonable time frame. The Utilities Commission could also be entrusted with this responsibility wherein it keeps a track of outstanding payments and arrange for their recovery by suitably devised measures.

In addition to some of the institutional measures listed above there are likely to be technical problems as well, relating to the introduction of time-of-day meters in order to accurately measure electricity consumption. There would also be stiff resistance from various categories of consumers, in particular the relatively strong lobby of farmers, who would oppose the movement from the present flat rate tariffs that they enjoy to a metered system of supply. However, the need for moving over to a more efficient system of prices is indisputable in the long term interest of the economy and there is thus a need for strong political will to enact these changes.

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Annexure 4.2.1

Chronological information on coal price revisions

Date of revision	Basis	Loss in revenue resulting from disallowance of expense items					
		Year	Interest	Depre-ciation	Return	Total	Cumulative total
01.04.74	Estimated cost of production excluding interest & rate of return	1974-75	10.60	-	18.52	29.12	29.12
01.07.75	Estimated cost of production excluding depreciation, interest & rate of return	1975-76	24.08	25.52	22.96	72.56	101.68
		1976-77	26.02	29.90	22.94	78.86	180.54
		1977-78	25.75	29.59	22.71	78.05	258.59
		1978-79	25.50	29.31	22.49	77.30	335.89
17.07.79	Estimated cost of production including 10% rate of return on capital employed	1979-80	7.63	8.77	6.73	23.13	359.02
14.02.81	-Do-						
27.05.82	-Do-						
08.01.84	Estimated 1984-85 cost 50% increase from 1983-84 for interest & depreciation excluding rate of return	1983-84	3.22	2.31	45.00	50.53	409.55
		1984-85	15.26	10.93	213.17	239.36	648.91
		1985-86	12.12	8.86	218.41	239.21	888.12
09.01.86	Estimated 1986-87 cost of production excluding rate of return						
23.12.87	Normative cost updated to January 1987 (net block for depreciation March 1985)	1986-87			235.78	235.78	1123.90
		1987-88			190.46	190.46	1314.36
01.01.89	Normative cost updated to June 1988 including interest relief						
		Total	150.18	145.01	1019.17	1314.36	

Source : Coal India Limited

Annexure 4.2.2

Production of Coal from Singareni Coalfields

(lakh tonnes)

Grade	1989-90 (till Jan)	1988-89	1987-88	1986-87
C	16.31	23.40	17.71	17.35
D	37.77	41.01	33.66	48.81
E	55.40	74.81	70.43	49.47
F	33.67	45.96	38.62	30.58
G	0.93	0.87	3.59	15.49
Total	144.08	186.05	164.01	161.70

Source: Department of Coal, GOI.

Annexure 4.2.3

Supply of Coal from NECL to Steel Plants

Year	Total Production* of NECL (Mt)	Supply to Steel Plants (Mt)	Share of Supply to Steel Plants (%)
1982-83	0.71	0.02	2.8
1983-84	0.80	0.13	16.2
1984-85	0.81	0.16	19.7
1985-86	0.84	0.15	17.9
1986-87	0.91	0.23	25.3

* Production from NECL has been classified under superior quality non-coking coal containing low ash content but high sulphur content.

Source: Operational Statistics 1974-75 to 1986-87, CIL.

Annexure 5.1.1

Economic cost of transportation by rail (for specific O-D combinations)

Source	Destination	Distance (Kms)	Transportation cost (Rs/lit) MS	ATF	HSD	FO	SKO	LPG*
Bombay	Delhi	1388	0.21	0.23	0.25	0.28	0.23	0.3
	Kanpur	1533	0.23	0.25	0.27	0.30	0.25	0.3
	Calcutta	2173	0.31	0.34	0.36	0.41	0.34	0.4
Madras	Delhi	2157	0.31	0.34	0.36	0.41	0.34	-
	Kanpur	-	-	-	-	-	-	-
	Calcutta	1678	0.24	0.27	0.29	0.32	0.27	-
Haldia	Delhi	1455	0.23	0.25	0.27	0.30	0.25	0.3
	Kanpur	1017	0.18	0.19	0.21	0.23	0.19	0.2
	Calcutta	136	0.05	0.06	0.06	0.07	0.06	0.0
Vizag	Calcutta	784	0.14	0.15	0.16	0.18	0.15	0.2
	Madras	885	0.15	0.16	0.17	0.20	0.16	0.2
Mangalore	Madras	845	-	-	-	-	-	-

* refers to cost (Rs/kg)

B. Marginal cost of supply of various petroleum products by rail (for specific O-D combinations)

Source	Destination	Distance (Kms)	Cost of supply (Rs/lit) MS	ATF	HSD	FO	SKO	LPG*
Bombay	Delhi	1388	3.15	2.83	3.05	2.02	3.23	6.49
	Kanpur	1533	3.17	2.85	3.07	2.04	3.26	6.65
	Calcutta	2173	3.25	2.93	3.16	2.15	3.33	6.76
Madras	Delhi	2157	3.25	2.97	3.20	2.44	3.31	-
	Kanpur	1938	3.24	2.95	3.18	2.42	3.30	-
	Calcutta	1678	3.19	2.90	3.12	2.36	3.23	-
Haldia	Delhi	1455	3.18	2.88	3.11	2.34	3.23	6.65
	Kanpur	1017	3.13	2.83	3.05	2.27	3.18	6.71
	Calcutta	136	3.00	2.69	2.90	2.11	3.02	6.53
Vizag	Calcutta	784	3.10	2.79	3.01	2.23	3.13	6.53
	Madras	885	3.09	2.78	3.00	2.22	3.11	6.38
Mangalore	Madras	845	-	-	-	-	-	6.53
At Bombay			2.94	2.60	2.80	1.74	3.00	6.18
At Madras			2.95	2.63	2.84	2.03	2.96	-

* refers to cost (Rs/kg)

C. Marginal cost of supply of selected petroleum products by rail (by distance slabs)

Distance slab	Cost of transportation	Total cost of supply					
		MS		ATF		HSD	
(Kms)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)
upto 250	77.72	3.00	4284.34	2.68	3455.13	2.89	3499.01
250-500	122.93	3.03	4329.55	2.72	3500.34	2.93	3544.22
500-750	167.39	3.07	4374.01	2.75	3544.80	2.97	3588.68
750-1000	209.04	3.09	4415.66	2.78	3586.45	3.00	3630.33
1000-1250	263.80	3.13	4470.42	2.83	3641.21	3.05	3685.09
1250-1500	322.40	3.17	4529.02	2.87	3699.81	3.09	3743.68
1500-1750	367.72	3.21	4574.34	2.91	3745.13	3.13	3789.01
1750-2000	413.05	3.24	4619.67	2.94	3790.46	3.17	3834.33
2000-2250	458.37	3.27	4664.99	2.98	3835.78	3.21	3879.66
2250-2500	503.70	3.30	4710.32	3.01	3881.11	3.24	3924.98
2500-2750	549.02	3.33	4755.64	3.05	3926.43	3.28	3970.31
2750-3000	594.35	3.36	4800.97	3.08	3971.76	3.32	4015.64

Distance slab	Cost of transportation	Total cost of supply					
		FO		SKO		LPG	
(Kms)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/kg)	(Rs/tonne)
upto 250	77.72	1.99	2126.27	3.04	3907.28	6.30	6299.66
250-500	122.93	2.03	2171.48	3.08	3952.49	6.34	6344.87
500-750	167.39	2.07	2215.94	3.11	3996.95	6.39	6389.33
750-100	209.040	2.11	2257.59	3.14	4038.60	6.43	6430.98
1000-125	263.800	2.16	2312.35	3.19	4093.36	6.49	6485.74
1250-150	322.400	2.21	2370.95	3.23	4151.96	6.54	6544.34
1500-175	367.720	2.26	2416.27	3.27	4197.28	6.59	6589.66
1750-200	413.050	2.30	2461.60	3.30	4242.61	6.63	6634.99
2000-225	458.370	2.34	2506.92	3.34	4287.93	6.68	6680.31
2250-250	503.700	2.38	2552.25	3.37	4333.26	6.73	6725.64
2500-275	549.020	2.43	2597.57	3.41	4378.59	6.77	6770.96
2750-300	594.350	2.47	2642.90	3.44	4423.91	6.82	6816.29

ANNEXURE 5.1.2

A. Economic cost of transportation by road (for specific O-D combinations)

Source	Destination	Distance (Kms)	MS	ATF	HSD	FO	SKO	LPG*
			Transportation cost (Rs/lit)					
Bombay	Delhi	1388	0.58	0.65	0.69	0.77	0.65	0.8[illegible]
	Kanpur	1533	0.63	0.70	0.75	0.84	0.70	0.9[illegible]
	Calcutta	2173	0.89	0.98	1.05	1.18	0.99	1.2[illegible]
Madras	Delhi	2157	0.89	0.98	1.05	1.18	0.99	-
	Kanpur	-	-	-	-	-	-	-
	Calcutta	1678	0.68	0.76	0.81	0.91	0.76	-
Haldia	Delhi	1455	0.63	0.70	0.75	0.84	0.70	0.7[illegible]
	Kanpur	1017	0.47	0.52	0.55	0.63	0.52	0.6[illegible]
	Calcutta	136	0.07	0.08	0.08	0.09	0.08	0.1[illegible]
Vizag	Calcutta	784	0.35	0.38	0.41	0.47	0.39	0.5[illegible]
	Madras	885	0.41	0.45	0.48	0.55	0.46	0.5[illegible]
Mangalore	Madras	845	-	-	-	-	-	0.5[illegible]

* refers to cost (Rs/kg)

B. Marginal cost of supply of selected petroleum products by road (for specific O-D combinations)

Source	Destination	Distance (kms)	MS	ATF	HSD	FO	SKO	LPG*
			Cost of supply (Rs/lit)					
Bombay	Delhi	1388	3.53	3.24	3.49	2.52	3.65	7.02
	Kanpur	1533	3.58	3.30	3.55	2.59	3.71	7.23
	Calcutta	2173	3.83	3.58	3.85	2.92	3.98	7.59
Madras	Delhi	2157	3.84	3.61	3.88	3.22	3.96	-
	Kanpur	1938	3.79	3.57	3.82	3.15	3.78	-
	Calcutta	1678	3.63	3.39	3.64	2.95	3.72	-
Haldia	Delhi	1455	3.59	3.34	3.59	2.88	3.68	7.11
	Kanpur	1017	3.42	3.15	3.39	2.66	3.51	7.13
	Calcutta	136	3.02	2.71	2.92	2.13	3.05	6.56
Vizag	Calcutta	784	3.36	3.08	3.32	2.58	3.42	6.91
	Madras	885	3.30	3.02	3.25	2.50	3.35	6.69
Mangalore	Madras	-	-	-	-	-	-	6.91

* refers to cost (Rs/kg)

C. Marginal cost of supply of selected petroleum products by road (by distance slabs)

Distance slab	Cost of transportation	Total cost of supply					
		MS		ATF		HSD	
(Kms)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)
upto 250	117.61	3.03	4324.23	2.71	3495.02	2.92	3538.90
250-500	271.09	3.14	4477.71	2.83	3648.50	3.05	3692.37
500-750	409.78	3.24	4616.40	2.94	3787.19	3.17	3831.07
750-1000	540.87	3.33	4747.49	3.04	3918.28	3.27	3962.16
1000-1250	714.76	3.45	4921.38	3.18	4092.17	3.42	4136.05
1250-1500	904.88	3.58	5111.50	3.32	4282.29	3.58	4326.17
1500-1750	1050.03	3.68	5256.65	3.44	4427.44	3.70	4471.32
1750-2000	1195.17	3.79	5401.79	3.55	4572.58	3.82	4616.46
2000-2250	1340.32	3.89	5546.94	3.66	4717.73	3.94	4761.61
2250-2500	1485.46	3.99	5692.08	3.78	4862.87	4.06	4906.75
2500-2750	1630.61	4.09	5837.23	3.89	5008.02	4.18	5051.90
2750-3000	1775.75	4.19	5982.37	4.00	5153.16	4.30	5197.04

Distance slab	Cost of transportation	Total cost of supply					
		FO		SKO		LPG	
(Kms)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/kg)	(Rs/tonne)
upto 250	117.61	2.02	2166.16	3.07	3947.17	6.34	6339.55
250-500	271.09	2.17	2319.64	3.19	4100.65	6.49	6493.03
500-750	409.78	2.30	2458.33	3.30	4239.34	6.63	6631.72
750-1000	540.87	2.42	2589.42	3.40	4370.44	6.76	6762.82
1000-1250	714.76	2.58	2763.31	3.54	4544.33	6.94	6936.71
1250-1500	904.88	2.76	2953.43	3.68	4734.44	7.13	7126.82
1500-1750	1050.03	2.89	3098.58	3.80	4879.59	7.27	7271.97
1750-2000	1195.17	3.03	3243.72	3.91	5024.73	7.42	7417.11
2000-2250	1340.32	3.16	3388.87	4.02	5169.88	7.56	7562.26
2250-2500	1485.46	3.30	3534.01	4.14	5315.02	7.71	7707.40
2500-2750	1630.61	3.44	3679.16	4.25	5460.17	7.85	7852.55
2750-3000	1775.75	3.57	3824.30	4.36	5605.31	8.00	7997.69

ANNEXURE 5.1.

A. Economic cost of transportation by pipeline (for specific O-combinations)

Source	Destination	Distance (kms)	Transportation cost (Rs/lit) MS	ATF	HSD	FO	SKO
Bombay	Delhi	1186	0.32	0.35	0.38	0.42	0.35
	Kanpur	1120	0.34	0.37	0.40	0.45	0.37
	Calcutta	1630	0.49	0.54	0.58	0.65	0.55
Madras	Delhi	1577	0.16	0.17	0.19	0.21	0.17
	Kanpur	1192	0.04	0.05	0.04	0.05	0.05
	Calcutta	84	0.002	0.003	0.003	0.003	0.003
Vizag	Calcutta	780	0.23	0.26	0.28	0.31	0.26
	Madras	750	0.23	0.25	0.27	0.30	0.25

B. Marginal cost of supply of selected petroleum products by pipeline (for specific O-D combinations)

Source	Destination	Distance (kms)	Cost of supply (Rs/lit) MS	ATF	HSD	FO	SKO
Bombay	Delhi	1186 (1)	3.26	2.95	3.17	2.16	3.35
	Kanpur	1120	3.28	2.97	3.20	2.19	3.38
	Calcutta	1630	3.43	3.14	3.38	2.39	3.53
Haldia	Delhi	1577 (2)	3.11	2.81	3.03	2.25	3.15
	Kanpur	1192 (3)	2.99	2.68	2.89	2.09	3.03
	Calcutta	84	2.95	2.64	2.84	2.04	2.97
Vizag	Calcutta	780	3.17	2.88	3.10	2.34	3.21
	Madras	750	3.18	2.89	3.11	2.35	3.22

(1) New pipeline from Bombay to Mathura (1040 kms) and existing pipelin from Mathura to Delhi (146 kms)

(2) New pipeline from Kanpur to Delhi (385 kms) and existing pipeline from Haldia to Barauni (524 kms) and Barauni to Kanpur (668 kms)

(3) Existing pipelines from Haldia to Barauni (524 kms) and Barauni to Kanpur (668 kms)

A. Economic cost of transportation by coast (for specific O-D combinations)

Source	Destination	Distance (Kms)	MS	ATF	HSD	FO	SKO
			Transportation cost (Rs/lit)				
Bombay	Madras	1458	0.11	0.13	0.14	0.15	0.13
	Vizag	1737	0.12	0.13	0.14	0.16	0.13
	Calcutta	2112	0.13	0.14	0.15	0.17	0.14
Madras	Vizag	458	0.07	0.07	0.08	0.09	0.07
	Calcutta	775	0.07	0.08	0.09	0.10	0.08
	Haldia	1111	0.08	0.09	0.09	0.10	0.07

B. Marginal cost of supply of selected petroleum products by coastal shipping (for specific O-D combinations)

(Rs/lit)

Source	Destination	Distance (Kms)	MS	ATF	HSD	FO	SKO
Bombay	Madras	1458	3.06	2.73	2.94	1.89	3.11
	Vizag	1737	3.07	2.73	2.94	1.90	3.12
	Calcutta	2112	3.07	2.74	2.95	1.91	3.13
Madras	Vizag	458	3.02	2.70	2.91	2.12	3.03
	Calcutta	775	3.02	2.71	2.92	2.13	3.04
	Haldia	1111	3.03	2.72	2.93	2.14	3.04

C. Marginal cost of supply of selected petroleum products by coast (by distance slabs)

Distance slab	Cost of transportation	Total cost of supply					
		MS		ATF		HSD	
(Kms)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)
250-500	152.54	3.05	4359.16	2.74	3529.95	2.95	3573.83
500-750	156.43	3.06	4363.05	2.74	3533.84	2.96	3577.71
750-1000	162.26	3.06	4368.88	2.75	3539.67	2.96	3583.55
1000-1250	170.04	3.07	4376.66	2.75	3547.46	2.97	3591.33
1250-1500	178.48	3.07	4385.10	2.76	3555.89	2.98	3599.77
1500-1750	184.95	3.08	4391.57	2.77	3562.36	2.98	3606.24
1750-2000	191.45	3.08	4398.07	2.77	3568.86	2.99	3612.73
2000-2250	197.93	3.09	4404.55	2.78	3575.34	2.99	3619.22
2250-2500	204.40	3.09	4411.02	2.78	3581.82	3.00	3625.69
2500-2750	210.90	3.10	4417.52	2.79	3588.31	3.00	3632.19
2750-3000	217.38	3.10	4424.00	2.79	3594.80	3.01	3638.67

Distance slab	Cost of transportation	Total cost of supply					
		FO		SKO		LPG	
(Kms)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/lit)	(Rs/tonne)	(Rs/Kg)	(Rs/tonne)
250-500	152.54	2.06	2201.09	3.10	3982.10	6.37	6374.48
500-750	156.43	2.06	2204.98	3.10	3985.99	6.38	6378.37
750-1000	162.26	2.06	2210.81	3.11	3991.82	6.38	6384.20
1000-1250	170.04	2.07	2218.59	3.11	3999.61	6.39	6391.99
1250-1500	178.48	2.08	2227.03	3.12	4008.04	6.40	6400.42
1500-1750	184.95	2.09	2233.50	3.12	4014.51	6.41	6406.89
1750-2000	191.45	2.09	2240.00	3.13	4021.01	6.41	6413.39
2000-2250	197.93	2.10	2246.48	3.13	4027.49	6.42	6419.87
2250-2500	204.40	2.10	2252.95	3.14	4033.97	6.43	6426.35
2500-2750	210.90	2.11	2259.45	3.14	4040.46	6.43	6432.84
2750-3000	217.38	2.12	2265.93	3.15	4046.95	6.44	6439.33

ANNEXURE 5.1.5

Retail selling price of selected petroleum products in major cities/towns as on 1.4.1987

City/town	Retail selling price (Rs/lit)					
	MS	ATF*	HSD	FO	SKO	LPG**
Bombay	7.99	6.60	3.63	3.10	2.17	3.95
Delhi	7.43	5.76	3.50	3.25	2.25	4.06
Kanpur	7.85	6.08	3.84	--	2.50	4.34
Calcutta	7.60	5.47	3.59	3.18	2.27	4.45
Madras	7.84	6.08	3.64	3.26	2.25	4.03

* refers to ATF being sold to domestic airlines
** in Rs/kg
Source [3]

Annexure 5.2.1

Linear Regression Approach

With a view to establish a relationship between the unit investment requirement and some key factors characterizing the investment scheme viz., the date of sanction, date of completion, gestation period, capacity size, etc. a Linear Regression Method based on Ordinary Least Squares was adopted.

A closer observation of data revealed that actual capital expenditure of the scheme was invariably different from the sanctioned capital. Therefore, the sample of mines chosen for analysis contained only new projects for which data on actual investment at the time of projection completion was available. Also, since there were very few observations present in the OCDL and UGLW group of mines, the regression analysis was restricted to the OCSD and UGBP group of mines.

The relationships which were attempted and the results obtained are summarized as follows:

(1) Investment and ultimate capacity

An attempt was made to relate unit investment cost to the total mine capacity reached at the time of project completion. The results of the regression analysis are presented below.

OCSD

Regression equation

I = 20.87 + 0.39 * C

where,

I = Investment (Rs. crores/mt of ultimate capacity)

C = Ultimate capacity (mt/year)

Number of observations : n = 38

Number of explanatory variables : k = 1

Statistical parameters

Coefficient of determination : R^2 = .0015

t-statistic for coefficient of C : t_a = 0.235

Therefore, $t_a < t^*_a$ with n-k-1 = 38-1-1 = 36 d.o.f. at 5% LOS

where,

t_a = estimated sample value of t statistic

t^*_a = actual tabulated value of t statistic

d.o.f. = degrees of freedom

LOS = level of significance

UGBP

Regression equation :

I = 17.39 + 1.61 * C

Number of observations : n = 28

Number of explanatory variables : k = 1

Statistical parameters:

Coefficient of determination : R^2 = 0.0016

t-statistic for coefficient of C : t_a = 0.206

Therefore, $t_c < t^*_c$ with n-k-1 = 28-1-1 = 26 d.o.f. at 5% LOS

The above results and the graphical presentations in Figures 1 and 2 indicated that unit investment expenditure was not dependent upon the capacity installed. The value of R^2 was very low and the value of t-statistic was not statistically significant.

Figure 1. Relationship between Investment[1] and Capacity - Opencast - Shovel and Dumper Technology

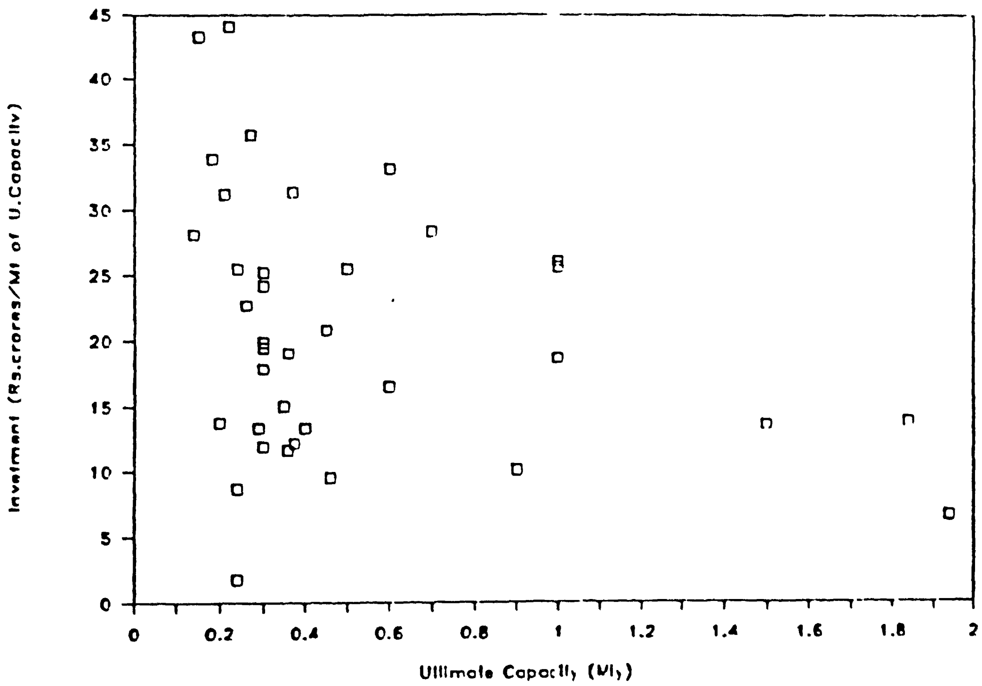
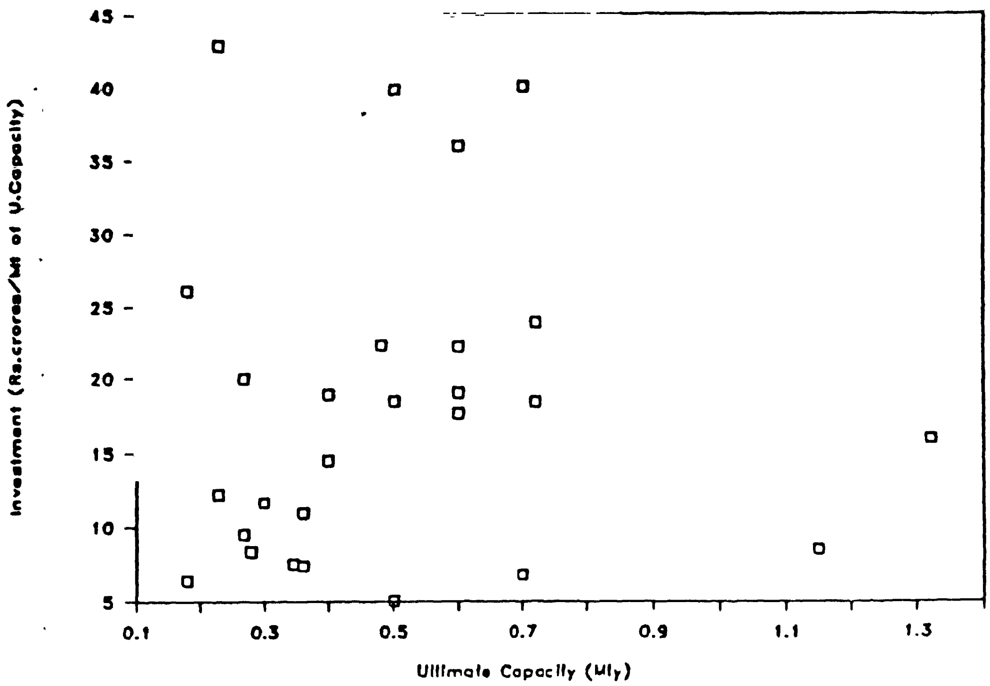


Figure 2. Relationship between Investment and Capacity - Underground - Bord and Pillar Technology



(2) <u>Investment and date of sanction of the project</u>

The date of sanction varied across different mining projects, there was, thus, a need to calculate all investments in 1987-88 constant prices. In order to take into account the cost escalations, unit investment was related to its year of sanction by introducing a dummy variable for the latter. The value assigned to the dummy was 1 if the project was sanctioned in a particular year and 0 if it was not. This implies that, in the absence of data on time distribution of investments, a restrictive assumption was made that all investment expenditure takes place in the year of project sanction. The trend in coefficients associated with the dummies would be indicative of the price index of mining costs and could be used for bringing all costs in constant base year prices of 1987-88.

The results obtained are as follows :

OCSD

Regression e·uation :

$$I = 16.50*d_1 + 9.57*d_2 + 16.85*d_3 + 12.81*d_4 + 20.80*d_5 + 20.83*d_6 + 25.09*d_7 + 22.00*d_8 + 19.74*d_9 + 8.40*d_{10} + 36.23*d$$

where

d_1 = dummy variable for 1975

d_2 = dummy variable for 1976

d_3 = dummy variable for 1978

d_4 = dummy variable for 1979

d_5 = dummy variable for 1980

d_6 = dummy variable for 1981

d_7 = dummy variable for 1983

d_8 = dummy variable for 1984

d_9 = dummy variable for 1985

d_{10} = dummy variable for 1986

d_{11} = dummy variable for 1987

Number of observations : n = 38

Number of explanatory variables : k = 11

Statistical parameters :

Coefficient of determination : R^2 = 0.23

t-statistic

t_{d1} = 1.61

t_{d2} = 0.936

t_{d3} = 3.69

t_{d4} = 2.507

t_{d5} = 2.035

t_{d6} = 4.076

t_{d7} = 7.768

t_{d8} = 4.305

t_{d9} = 3.863

t_{d10} = 0.736

t_{d11} = 5.018

<u>t-test</u> :

$t_{d1} < t^*_{d1}$

$t_{d2} < t^*_{d2}$

$t_{d3} > t^*_{d3}$

$t_{d4} > t^*_{d4}$

$t_{d5} > t^*_{d5}$

$t_{d6} > t^*_{d6}$

$t_{d7} > t^*_{d7}$

$t_{d8} > t^*_{d8}$

$t_{d9} > t^*_{d9}$

$t_{d10} < t^*_{d10}$

$t_{d11} > t^*_{d11}$ with n-k = 38-11 = 27 d.o.f. and at 5% LOS

where,

t_{d1} to t_{d11} = estimated sample values of t statistic

t^*_{d1} to t^*_{d11} = tabulated values of t statistic

<u>UGBP</u>

<u>Regression equation</u> :

$$I = 8.47*d_1 + 9.99*d_2 + 18.90*d_3 + 11.40*d_4 + 22.23*d_5 + 19.20*d_6 + 21.95*d_7 + 23.95*d_8 + 35.93*d_9 + 42.84*d_{10} + 39.83*d_{11}$$

where,

I = Investment (Rs. crores/mt of ultimate capacity)

d_1 = dummy variable for 1978

d_2 = dummy variable for 1979

d_3 = dummy variable for 1980

d_4 = dummy variable for 1981

d_5 = dummy variable for 1982

d_6 = dummy variable for 1983

d_7 = dummy variable for 1984

d_8 = dummy variable for 1985

d_9 = dummy variable for 1986

d_{10} = dummy variable for 1987

d_{11} = dummy variable for 1988

Number of observations : $n = 28$

Number of explanatory variables : $k = 11$

<u>Statistical parameters</u> :

Coefficient of determination : $R^2 = 0.66$

t-statistic

$t_{d1} = 1.075$

$t_{d2} = 3.102$

$t_{d3} = 4.797$

$t_{d4} = 2.047$

$t_{d5} = 2.821$

$t_{d6} = 5.962$

$t_{d7} = 3.941$

$t_{d8} = 3.039$

$t_{d9} = 4.56$

$t_{d10} = 5.437$

$t_{d11} = 5.055$

t-test :

$t_{d1} < t^*_{d1}$

$t_{d2} > t^*_{d2}$

$t_{d3} > t^*_{d3}$

$t_{d4} > t^*_{d4}$

$t_{d5} > t^*_{d5}$

$t_{d6} > t^*_{d6}$

$t_{d7} > t^*_{d7}$

$t_{d8} > t^*_{d8}$

$t_{d9} > t^*_{d9}$

$t_{d10} > t^*_{d10}$

$t_{d11} > t^*_{d11}$ with n-k = 28-11 = 17 d.o.f. and at 5% LOS

where,

t_{d1} to t_{d11} = estimated sample values of t statistic

t^*_{d1} to t^*_{d11} = tabulated values of t statistic

The statistical parameters indicated that in case of the OCSD technology of mining, the investment was not strongly related to the date of sanction. Although the coefficient of the dummy variables delineated a rising trend (as shown in Figure 3) and were also statistically significant for most explanatory variables, the value of R^2 was poor. In case of UGBP technology, both the statistical parameters viz. values of R^2 and the t-statistic indicated a reasonably strong dependence of the investment on the time of sanction. As is shown in Figure 4 the dummies depicted a steadily rising trend.

Figure 3. Trend in the Coefficient of Dummy Variables - Shovel and Dumper Technology

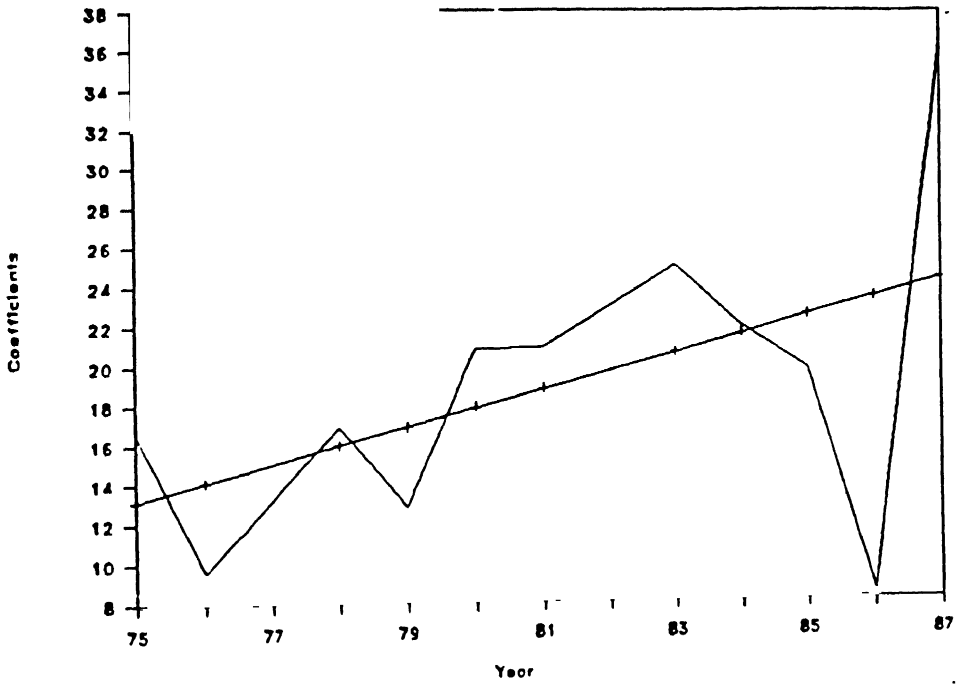
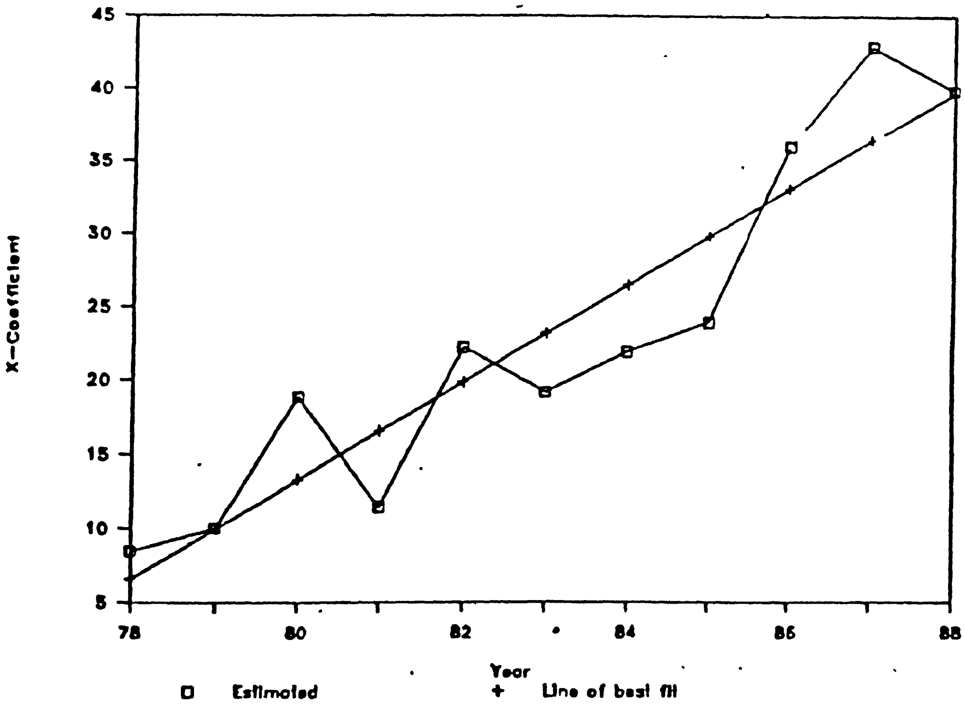


Figure 4. Trend in the Coefficient of Dummy Variables - Underground - Bord and Pillar Technology



(3) Investment with ultimate mine capacity and dummies for the year of sanction

Another multivariable regression analysis attempted related investment in mines to capacity and the dummies for the year of sanction of the project. The results of this regression analysis are summarized below.

OCSD

Re•ression equation :

$$I = 17.42 + 1.24*C - 1.66*d_1 - 8.42*d_2 - 1.35*d_3 - 5*d_4 + 2.82*d_5 + 3.14*d_6 + 7.27*d_7 + 3.41*d_8 - 0.33*d_9 + 10.87*d_{10} + 18.24*d_{11}$$

Number of observations : n = 38

Number of explanatory variables : k = 12

Statistical parameters :

Coefficient of determination : $R^2 = 0.34$

t-statistic

$t_o = 0.621$

$t_{d1} = 0.119$

$t_{d2} = 0.602$

$t_{d3} = 0.124$

$t_{d4} = 0.45$

$t_{d5} = 0.201$

$t_{d6} = 0.282$

$t_{d7} = 0.696$

$t_{d8} = 0.309$

$t_{d9} = 0.029$

$t_{d10} = 0.927$

$t_{d11} = 1.504$

Statistical test :

$t_{d1} < t^*_{d1}$

$t_{d2} < t^*_{d2}$

$t_{d3} < t^*_{d3}$

$t_{d4} < t^*_{d4}$

$t_{d5} < t^*_{d5}$

$t_{d6} < t^*_{d6}$

$t_{d7} < t^*_{d7}$

$t_{d8} < t^*_{d8}$

$t_{d9} < t^*_{d9}$

$t_{d10} < t^*_{d10}$

$t_{d11} < t^*_{d11}$ with n-k-1 = 38-12-1 = 25 d.o.f. and at 5% LOS.

where, t_{d1} to t_{d11} = estimated sample values

t^*_{d1} to t^*_{d11} = tabulated values

UGBP

Regression equation :

$$I = 7.43 + 4.45*C - 4.08*d_1 + 0.76*d_2 + 9.13*d_3 + 2.46*d_4 + 12.13*d_5 + 9.26*d_6 + 12.78*d_7 + 13.32*d_8 + 25.83*d_9 + 34.38*d_{10} + 30.17*d_{11}$$

Number of observations : n = 28

Number of explanatory variables : k = 12

Statistical parameters :

Coefficient of determination : R^2 = 0.725

t-values

t_c = 0.654

t_{d1} = 0.394

t_{d2} = 0.124

t_{d3} = 1.398

$t_{a4} = 0.324$

$t_{a5} = 1.309$

$t_{a6} = 1.497$

$t_{a7} = 1.694$

$t_{a8} = 1.419$

$t_{a9} = 2.787$

$t_{a10} = 3.67$

$t_{a11} = 3.27$

<u>t-test</u> :

$t_{a1} < t^{*}_{a1}$

$t_{a2} < t^{*}_{a2}$

$t_{a3} < t^{*}_{a3}$

$t_{a4} < t^{*}_{a4}$

$t_{a5} < t^{*}_{a5}$

$t_{a6} < t^{*}_{a6}$

$t_{a7} < t^{*}_{a7}$

$t_{a8} < t^{*}_{a8}$

$t_{a9} > t^{*}_{a9}$

$t_{a10} > t^{*}_{a10}$

$t_{a11} > t^{*}_{a11}$ with n-k-1 = 28-12-1 = 15 d.o.f. and at 5% LOS.

An examination of the above results showed that for OCSD group of mines the value of R^2 was quite low and the t values were not statistically significant. This implied that the variation in investment per unit of ultimate capacity was not explained by variation in the explanatory variables of capacity and time.

In the second case of UGBP technology, the data did illustrate a strong dependence of investment - both on the capacity and the dummies representing the date of sanction.

(4)Investment and mid year of the gestation period

It was also attempted to relate unit investment to the mid point of the project construction period. This tantamounts to having the entire investment expenditure occurring at the midpoint of the gestation period. The results of this regression are summarized below:

OCSD

Regression equation :

$I = -130.9 + 0.005*M$

where,

I = Investment (Rs.crores/mt of ultimate capacity)

M = Mid year of construction period

Number of observations : n = 38

Number of explanatory variables : k = 1

Statistical parameters :

Coefficient of determination : $R^2 = 0.18$

t-statistic

$t_M = 2.76$

$t_M > t^*_M$ with n-k-1 = 36 d.o.f. and at 5% LOS.

UGBP

Regression equation :

$I = -232.48 + 0.01*M$

Number of observations : n = 28

Number of explanatory variables : k = 1

Statistical parameters :

Coefficient of determination : $R^2 = 0.43$

t-statistic

$t_M > t^*_M$

A perusal of the above results showed that, in case of OCSD technology, investment was not related to the midpoint of the gestation period as the value of R^2 was quite low. However, in case of UGBP mines, the value of R^2 was relatively higher as compared to OCSD mines. A graphical presentation of these results is given in Figures 5 and 6 below.

Figure 5. Relationship between Investment and Midpoint of the Gestation Period - Opencast-Shovel and Dumper Technology

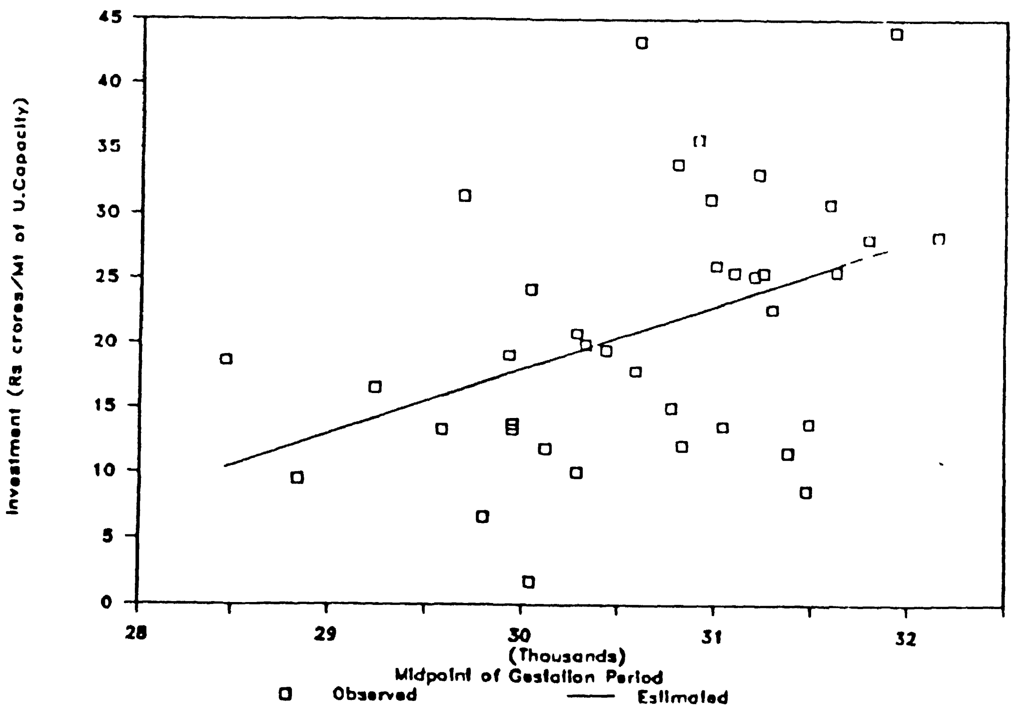
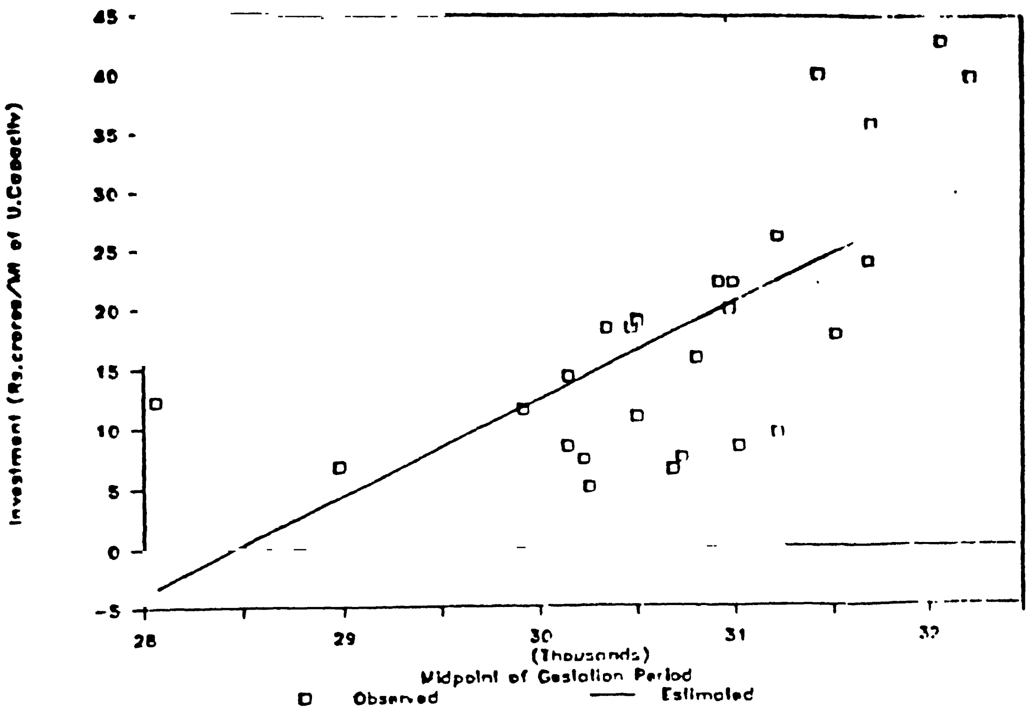


Figure 6. Relationship between investment and Midpoint of the Gestation Period Underground - Bord and Fillon Technology



(5) Investment and gestation period

OCSD

Regression equation :

I = 25.81 - 0.0036*G

where,

G = Gestation period of the project(days)

Number of observations : n = 38

Number of explanatory variables : k = 1

Statistical parameters :

Coefficient of determination : R^2 = 0.081

t-statistic

t_o = 1.38

t-test

$t_o < t^*_o$ with n-k-1 = 38-1-1 = 36 d.o.f. and at 5% LOS.

UGBP

Regression equation :

$I = 30.87 - 0.0077*G$

where I = Investment (Rs.crores/Mt of ultimate capacity of mines)

G = Gestation period (days)

Number of observations : n = 28

Number of explanatory variables : k = 1

Statistical parameters :

Coefficient of determination : $R^2 = 0.43$

t-statistic

$t_a = 4.529$

t-test

$t_a > t^*_a$ with n-k-1 = 28-1-1 = 26 d.o.f. and at 5% LOS.

The result of the analysis showed that for OCSD mines, investment per unit of capacity was not related to the gestation period. However, in case of the UGBP mines, the value of R^2 was relatively higher as compared to the OCSD sample of mines (see Figures 7 and 8).

Figure 7. Relationship between investment and gestation period - Opencast - Shovel and Dumper technology

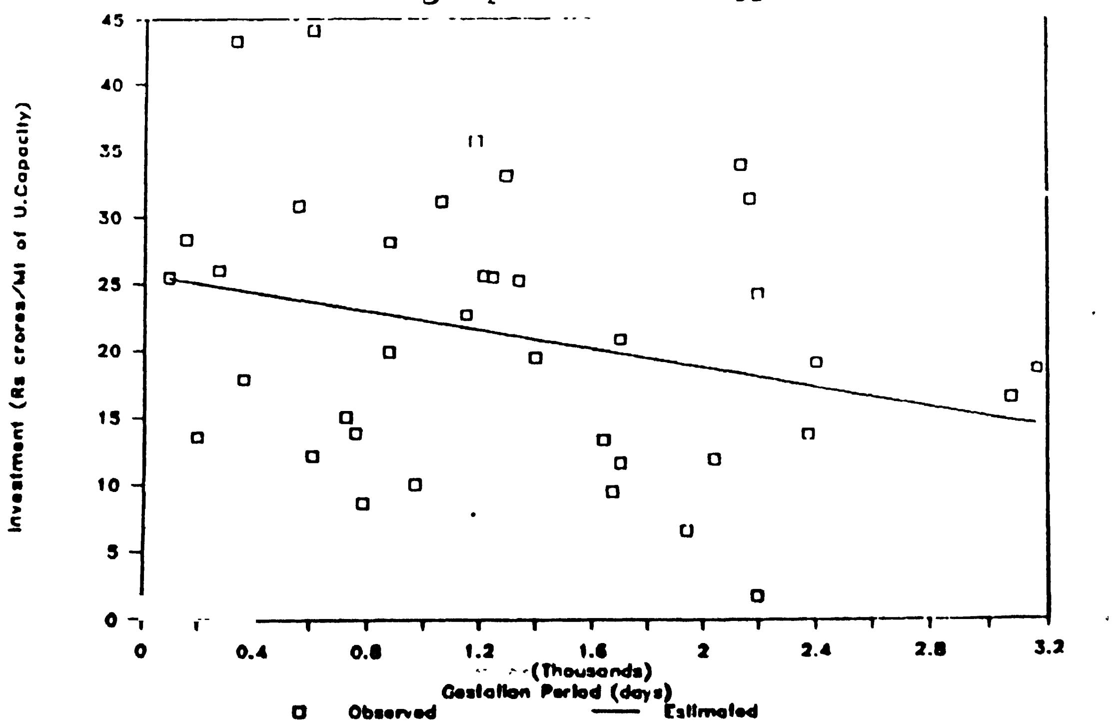
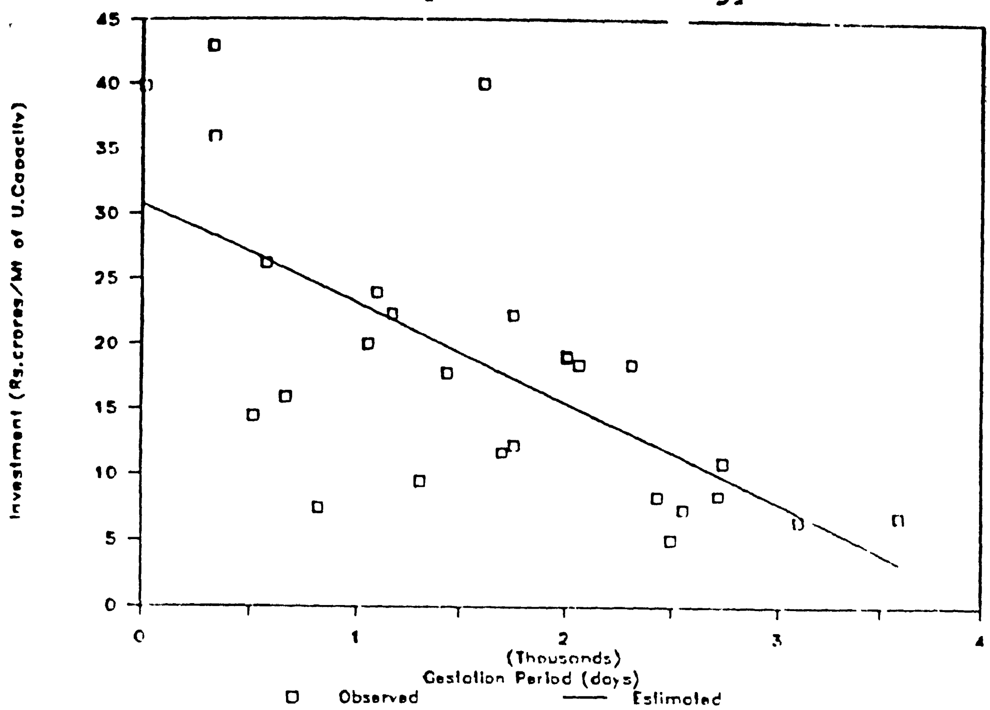


Figure 8. Relationship between investment and gestation period underground - Bord and pillar technology



To summarize, the results of the regression analysis showed that in case of OCSD technology of mining, investment per unit of capacity did not depict a strong relationship with any of the explanatory variables considered. In case of UGBP technology, although there was a reasonably strong relationship observed between unit investment and date of sanction of the project, it was quite weak with respect to other explanatory variables. Also, it is to be noted that:

- the date of sanction represented by dummies did not refer to the original date of sanction of the project. A number of projects are submitted for procuring additional finances during their period of construction. Thus, the date of sanction in such cases referred to the time when the revised project report was sanctioned & some additional money released for its completion.
- the data giving details about the distribution of investment over the gestation period of the project was not available. For the purpose of analysis a restrictive

assumption was made that all investments are made in the year of sanction itself which, however, is incorrect.

In view of the results obtained and the constraints discussed above, an alternative approach was adopted to estimate the normative costs for different technologies of mining. The methodology and the results of the alternative approach are discussed in Chapter 5.

Estimation of normative costs of investment (by type of mining technology)

(1) ef. o.	(2) Name of project	(3) Name of company	(4) Date of project sanction	(5) Ultimate capacity (mt/year)	(6) Sanctioned Capital (Rs.crores)	(7) Actual expenditure on completion (Rs.crores)	(8) Date of completion Scheduled	(9) Date of completion Actual	(10) Investment (Rs.crores/ mt) (7)/(5)	(11) Average investment (Rs.crores mt)
pencast dragline (OCDL)										
1	Jayant RCE	NCL	Jun-83	10.00	375.04	334.75	Mar-89	Mar-90	33.48	
2	Bina RCE	NCL	May-79	4.50	168.64	144.19	Mar-87	Mar-88	32.04	
										32.76
pencast shovel & dumper (OCSD)										
1	New Sawang	CCL	May-85	0.30	9.78	10.32	Mar-89	Mar-90	34.40	
2	Gevra	SECL	Sep-85	10.00	224.39	194.66	Mar-92	Mar-90	19.47	
3	Salanpur	BCCL	Sep-86	0.23	3.94	1.00	Mar-91	Mar-90	4.35	
4	Albion-B-J Patch	BCCL	Nov-86	0.21	3.98	3.34	Mar-89	Mar-90	15.90	
5	Laxman	SECL	Jul-88	0.80	19.15	8.70	Mar-91	Mar-90	10.88	
6	Karkatta	CCL	Aug-80	1.00	29.60	28.86	Mar-86	Jan-90	28.86	
7	Hindustan Lalpeth RCE	WCL	Nov-81	0.55	19.89	20.98	Mar-89	Mar-89	38.15	
8	Girija	ECL	Jan-82	0.24	6.29	8.99	Mar-89	Mar-89	37.46	
9	Sethia	WCL	Aug-86	0.22	9.70	9.70	Mar-89	Mar-88	44.09	
10	Rajnagar	SECL	Dec-84	1.00	25.54	25.59	Mar-87	Mar-88	25.59	
11	Pusai	ECL	Nov-83	0.24	8.04	6.13	Mar-87	Mar-87	25.54	
12	Banjemehari	ECL	Aug-83	0.30	9.90	7.58	Mar-86	Mar-87	25.27	
13	Sangramgarh	ECL	Feb-85	0.24	3.60	2.09	Mar-87	Mar-87	8.71	
14	Nirsha	ECL	Apr-84	0.26	8.67	5.90	Mar-89	Mar-87	22.69	
15	Kusmunda	SECL	Sep-85	6.00	168.45	185.26	Mar-88	Mar-87	30.88	
16	Jhingurdah	NCL	Jan-77	3.00	63.11	57.99	Mar-79	Mar-87	19.33	
17	Jamuna	SECL	Sep-83	0.60	18.07	19.88	Mar-84	Mar-87	33.13	
										24.98
nderground bord & pillar (UGBP)										
1	Rajnagar RO RCE	SECL	Jul-88	0.72	19.93	17.44	Mar-91	Mar-90	24.22	
2	New Chachai	SECL	Sep-83	0.60	12.38	11.53	Mar-86	Mar-89	19.22	
3	Bhatgaon RCE	SECL	Dec-74	0.50	19.92	19.92	Mar-89	Mar-88	39.83	
4	Shobapur	WCL	Jan-75	0.60	20.72	21.56	Mar-88	Mar-87	35.93	
ines producing prime coking coal										
pencast dragline (OCDL)										
1	Block-II	BCCL	-	2.50	183.64	183.64	-	-	73.46	
nderground longwall(UGLW)										
2	Moonidih	BCCL	Feb-83	2.10	132.07	183.79	Mar-85	Mar-89	87.52	
										80.49
ines producing medium coking coal										
pencast shovel & dumper (OCSD)										
1	Kedla RCE	CCL	Jul-78	0.70	19.86	19.86	Mar-84	Mar-88	28.37	
2	Rajrappa RCE	CCL	Sep-89	3.00	133.63	109.40	Mar-90	Mar-90	36.47	
nderground bord & pillar (UGBP)										
3	Laiyo	CCL	Nov-81	0.38	9.68	6.77	Mar-90	Mar-92	25.47	
										30.10

stimation of average incremental cost of production (by type of mining technology)

(1) ef. o.	(2) Name of the mine	(3) Name of the company	(4) Average grade of coal	(5) Ultimate capacity	(6) Production in 1987-88	(7) Estimated normative investment	(8) Total normative investment	(9) Distribution of total investme	(10)	(11)	(12
								Land	Buildings	P & M	Othe
				(mt/year)	(mt)	(Rs.crores in 1987-88 prices)	(Rs.crores in 1987-88 prices)	2%	6.5%	81.5%	10%
pencast dragline(OCDL)											
1	Jayant	NCL	C	10	5.340	32.76	327.60	6.55	21.29	266.99	32.
2	Bisrampur	SECL	B/C	1.25	1.033	32.76	40.95	0.82	2.66	33.37	4.
3	Jhingurdah	NCL	B	4.5	3.053	32.76	147.42	2.95	9.58	120.15	14.
pencast dragline(OCSD)											
1	New Majri	WCL	D/E	1	1.360	24.98	24.98	0.50	1.62	20.36	2.
2	Hindustan Lalpe	WCL	B/C	0.55	0.481	24.98	13.74	0.27	0.89	11.20	1.
3	Jamuna	SECL	C/D	0.6	0.682	24.98	14.99	0.30	0.97	12.22	1.
4	Rajnagar	SECL	D	1	1.249	24.98	24.98	0.50	1.62	20.36	2.
5	Sethia	WCL	D/E	0.22	0.433	24.98	5.50	0.11	0.36	4.48	0.
6	Kamptee	WCL	C	0.72	0.436	24.98	17.99	0.36	1.17	14.66	1.
7	Karkatta	CCL	E	1	1.590	24.98	24.98	0.50	1.62	20.36	2.
8	Bina	NCL	E	3	4.503	24.98	74.94	1.50	4.87	61.08	7.
9	Dakra	CCL	E	1.3	1.743	24.98	32.47	0.65	2.11	26.47	3.
10	Gevra	SECL	E/F	10	6.500	24.98	249.80	5.00	16.24	203.59	24.
11	Kusmunda	SECL	E/F	6	4.703	24.98	149.88	3.00	9.74	122.15	14.
12	Nichitpur	BCCL	F	0.45	0.240	24.98	11.24	0.22	0.73	9.16	1.
13	Manikpur	SECL	F	1.94	1.686	24.98	48.46	0.97	3.15	39.50	4.
14	G O C P	BCCL	W-III/W-I	0.72	0.822	24.98	17.99	0.36	1.17	14.66	1.
15	New Sawang OC	CCL	W-IV	0.3	0.294	24.98	7.49	0.15	0.49	6.11	0.
16	KOCP	BCCL	D	1	0.714	24.98	24.98	0.50	1.62	20.36	2.
nderground Bord & Pillar(UGBP)											
1	Rajnagar	SECL	A/B	0.72	0.471	29.80	21.46	0.43	1.39	17.49	2.
2	Pipla	WCL	B/C	0.5	0.270	29.80	14.90	0.30	0.97	12.14	1.
3	Bhatgaon	SECL	B/C	0.5	0.588	29.80	14.90	0.30	0.97	12.14	1.
4	Inder	WCL	C	0.4	0.340	29.80	11.92	0.24	0.77	9.71	1
5	Chachai	SECL	D/E	0.6	0.305	29.80	17.88	0.36	1.16	14.57	1.
6	Satpura	WCL	D/F	0.6	0.775	29.80	17.88	0.36	1.16	14.57	1.
7	Sarani	WCL	D/F	0.42	0.387	29.80	12.52	0.25	0.81	10.20	1.
8	Shobhapur	WCL	D/F	0.6	0.572	29.80	17.88	0.36	1.16	14.57	1.
ines producing prime coking coal											
pencast dragline(OCDL)											
1	Block-II	BCCL		2.5	2.125	80.49	201.23	4.02	13.08	164.00	20.
nderground longwall(UGLW)											
2	Moonidih	BCCL	W-II/W-II	2.1	1.050	80.49	169.03	3.38	10.99	137.76	16.
3	Sudamdih	BCCL	St-I/W-IV	1.65	0.825	80.49	132.81	2.66	8.63	108.24	13.
ines producing medium coking coal											
pencast shovel & dumper(OCSD)											
1	Rajrappa	CCL	W-II/W-II	3	2.036	30.10	90.30	1.81	5.87	73.59	
2	Kedla OC	CCL	W-III	0.7	0.499	30.10	21.07	0.42	1.37	17.17	
derground Bord & Pillar(UGBP)											
3	Laiyo	CCL		0.38		30.10	11.44	0.23	0.74	9.32	1.

f average incremental cost of production (by type of mining technology)

2) f the	(3) Name of the company	(13) Annualised capital cost: Land CRF*(9)	(14) Buildings CRF*(10)	(15) P & M CRF*(11)	(16) Others CRF*(12)	(17) Total (Rs. crores) (13)to(16)	(18) Annual capital cost* (Rs/ tonne)	(19) Salaries & Wages (Rs/ tonne)	(20) Overheads (Rs/ tonne)	(21) Stores (Rs/ tonne)	(22) Power (Rs/ tonne)
t dragline(OCDL)											
Jayant	NCL	0.79	2.56	35.74	4.39	43.48	51.15	13.71	2.38	65.50	13.37
Bisrampur	SECL	0.10	0.32	4.47	0.55	5.43	51.15	36.15	7.09	54.32	18.37
Jhingurdah	NCL	0.35	1.15	16.09	1.97	19.56	51.15	15.32	2.29	28.20	5.79
st dragline(OCSD)											
New Majri	WCL	0.06	0.20	3.82	0.33	4.41	51.89	22.66	7.80	39.15	3.53
Hindustan Lal	WCL	0.03	0.11	2.10	0.18	2.43	51.89	26.40	11.64	51.14	6.24
Jamuna	SECL	0.04	0.12	2.29	0.20	2.65	51.89	26.03	10.88	30.44	12.21
Rajnagar	SECL	0.06	0.20	3.82	0.33	4.41	51.89	17.36	10.85	27.81	9.73
Sethia	WCL	0.01	0.04	0.84	0.07	0.97	51.89	22.86	13.39	40.41	6.70
Kamptee	WCL	0.04	0.14	2.75	0.24	3.18	51.89	27.29	5.50	31.65	9.86
Karkatta	CCL	0.06	0.20	3.82	0.33	4.41	51.89	11.70	8.62	17.39	3.12
Bina	NCL	0.18	0.59	11.46	1.00	13.23	51.89	11.86	2.29	34.18	5.93
Dakra	CCL	0.08	0.25	4.97	0.43	5.73	51.89	41.27	7.35	20.74	4.18
Gevra	SECL	0.60	1.95	38.21	3.34	44.10	51.89	8.75	2.99	15.34	3.22
Kusmunda	SECL	0.36	1.17	22.93	2.01	26.46	51.89	17.23	3.68	27.54	6.41
Nichitpur	BCCL	0.03	0.09	1.72	0.15	1.98	51.89	52.71	23.65	44.14	5.08
Manikpur	SECL	0.12	0.38	7.41	0.65	8.56	51.89	24.11	6.32	46.66	7.14
G O C P	BCCL	0.04	0.14	2.75	0.24	3.18	51.89	52.79	12.47	26.00	5.20
5 New Sawang OC	CCL	0.02	0.06	1.15	0.10	1.32	51.89	138.77	12.86	66.49	25.69
6 KOCP	BCCL	0.06	0.20	3.82	0.33	4.41	51.89	57.40	13.85	30.82	6.38
rground Bord & Pillar(UGBP)											
1 Rajnagar	SECL	0.05	0.17	3.28	0.29	3.79	61.90	189.76	11.36	32.29	20.71
2 Pipla	WCL	0.04	0.12	2.28	0.20	2.63	61.90	146.60	6.79	30.87	22.77
3 Bhatgaon	SECL	0.04	0.12	2.28	0.20	2.63	61.90	77.93	5.17	26.90	14.14
4 Inder	WCL	0.03	0.09	1.82	0.16	2.10	61.90	169.30	7.29	30.40	32.52
5 Chachai	SECL	0.04	0.14	2.73	0.24	3.16	61.90	155.07	8.78	19.59	22.64
6 Satpura	WCL	0.04	0.14	2.73	0.24	3.16	61.90	96.31	7.26	30.61	15.96
7 Sarani	WCL	0.03	0.10	1.91	0.17	2.21	61.90	93.14	7.39	31.14	16.89
8 Shobhapur	WCL	0.04	0.14	2.73	0.24	3.16	61.90	96.42	7.16	37.92	17.35
s producing prime coking coal											
cast dragline(OCDL)											
1 Block-II	BCCL	0.48	1.57	21.96	2.69	26.71	125.67	70.39	7.80	57.82	6.7
rground longwall(UGLW)											
2 Moonidih	BCCL	0.41	1.32	25.85	2.26	29.84	284.23	133.07	26.05	56.04	42.75
3 Sudamdih	BCCL	0.32	1.04	20.31	1.78	23.45	284.23	300.89	23.50	62.44	68.08
s producing medium coking coal											
cast shovel & dumper(OCSD)											
1 Rajrappa	CCL	0.22	0.71	13.81	1.21	15.94	62.52	22.94	6.18	55.36	4.40
2 Kedla OC	CCL	0.05	0.16	3.22	0.28	3.72	62.52	63.44	14.59	60.32	10.90
rground Bord & Pillar(UGBP)											
3 Laiyo	CCL	0.03	0.09	1.75	0.15	2.02	62.52	275.49	18.63	44.61	10.7

ssuming an 85% capacity utilisation factor in case of OCDL, OCSD, & UGBP methods and a lower 50% capacity utilisation factor ase of UGLW method.

ANNEXURE 5.2.3

Estimation of average incremental cost of production (by type of mining technology)

(1) Ref. No.	(2) Name of the mine	(3) Name of the company	(23) Transport (Rs/ tonne)	(24) Others (Rs/ tonne)	(25) Total cost of production (Rs/ tonne) (18)to(24)	(26) Average cost of production (Rs/ tonne)	(27) Reference grade of coal
Opencast dragline(OCDL)							
1	Jayant	NCL	0.04	-15.43	131.72		C
2	Bisrampur	SECL	1.26	42.19	212.53		B/C
3	Jhingurdah	NCL	9.49	16.07	131.31		E
						156.52	
Opencast dragline(OCSD)							
1	New Majri	WCL	0.00	9.86	135.89		A/B
2	Hindustan Lal	WCL	4.54	48.65	202.50		B
3	Jamuna	SECL	4.41	56.47	195.33		C/D
4	Rajnagar	SECL	19.29	16.25	157.18		D
5	Sethia	WCL	-5.08	33.71	168.88		D
6	Kamptee	WCL	0.00	1.85	134.04		D
7	Karkatta	CCL	10.38	18.01	128.11		E
8	Bina	NCL	2.49	13.45	130.09		E
9	Dakra	CCL	2.45	35.82	172.70		E
10	Gevra	SECL	10.52	32.52	135.23		E/F
11	Kusmunda	SECL	1.17	3.69	122.61		E/F
12	Nichitpur	BCCL	0.00	126.16	315.63		F
13	Manikpur	SECL	0.59	-14.23	135.48	157.13	F/G
14	G O C P	BCCL	4.83	12.57	179.75		W-III
15	New Sawang OC	CCL	3.18	11.96	326.14		W-III
16	KOCP	BCCL	17.12	58.89	252.35		W-IV
						237.74	
Underground Bord & Pillar(UGBP)							
1	Rajnagar	SECL	2.90	12.91	332.83		B/C
2	Pipla	WCL	8.33	3.77	283.03		C
3	Bhatgaon	SECL	15.17	8.62	212.83		B/C
4	Inder	WCL	11.55	0.32	317.28		C
5	Chachai	SECL	0.00	18.58	291.56		C/D
6	Satpura	WCL	0.00	4.49	222.53		F
7	Sarani	WCL	0.00	5.28	222.74		F
8	Shobhapur	WCL	0.00	5.19	233.94		F
						260.09	
Mines producing prime coking coal							
Opencast dragline(OCDL)							
1	Block-II	BCCL	4.94	1.94	276.32		
Underground longwall(UGLW)							
2	Moonidih	BCCL	0.00	15.95	560.09		
3	Sudamdih	BCCL	0.00	21.27	763.41		
						531.27 PCC	
Mines producing medium coking coal							
Opencast shovel & dumper(OCSD)							
1	Rajrappa	CCL	0.14	31.69	184.23		
2	Kedla OC	CCL	0.00	26.92	240.69		
Underground Bord & Pillar(UGBP)							
3	Laiyo	CCL	8.68	-26.38	450.09	289.67 MCC	

Annexure 5.2.4

Distribution of total investment over major heads of capital

Ref. No.	Name of the mining scheme	Actual investment(Rs lakhs)					Percentage shares				
		Total investment	Land reclamation	Buildings	Plant & machinery	Others	Total investment	Land reclamation	Buildings	Plant & machinery	Other
1	Dudhichua	40496	16.00	1939	36749	1792	100	0.0	4.8	90.7	4.4
2	Rajmahal	56269.89	1096.50	4494.36	37165.20	13513.83	100	1.9	8.0	66.0	24.0
3	Bina	15706	69.00	1289	13385	963	100	0.4	8.2	85.2	6.1
4	Amlohri	41434	879.00	2027	34879	3649	100	2.1	4.9	84.2	8.8
5	Jayant	37504	841.00	2249	31424	2990	100	1.0	6.0	83.8	8.0
6	Katras	783781	2147.00	34333	699219	48082	100	0.3	4.4	89.2	6.1
7	Khadia	43752	372.00	2989	35495	4896	100	0.9	6.8	81.1	11.2
8	Nigahi	46304	1000.00	2582	37898	4824	100	2.2	5.6	81.8	10.4
9	Lingraj	18079.58	1248.50	1317.66	14023.17	1490.25	100	6.9	7.3	77.6	8.2
10	Dipka	37316.34	2300.00	2081.02	28310.34	4624.98	100	6.2	5.6	75.9	12.4

Source: CIL, New Delhi

ANNEXURE 5.2.5 contd...

Estimation of cost of washing of coking coal

A. Madhuband Washery for washing prime coking coals (capacity 2.5 mt/year)

(1) Ref.	(2) Type of capital stock	(3) Investment expenditure (million Rs. in Jan. 1989 prices) 1984-85	(4) 1985-86	(5) 1986-87	(6) Total	(7) Price index	(8) Investment expenditure (million Rs. in 1987-88 prices) 1984-85 (3)*(7)	(9) 1985-86 (4)*(7)	(10) 1986-87 (5)*(7)
1	Land	0.00	0.00	0.00	0.00	0.93	0.00	0.00	0.00
2	Buildings								
	-Residential	5.71	19.03	13.32	38.07	0.93	5.29	17.64	12.34
	-Service	66.66	100.95	87.62	255.22	0.93	61.77	93.54	81.19
3	Plant & machinery	153.24	243.02	211.28	607.54	0.91	138.97	220.39	191.60
4	Furniture	0.18	0.60	0.42	1.21	0.93	0.17	0.56	0.39
5	Railway siding	4.88	16.26	11.38	32.52	0.93	4.52	15.07	10.55
6	Vehicles	0.56	1.01	0.52	2.08	0.84	0.47	0.84	0.43
7	Development								
	-washery	2.66	0.00	0.00	2.66	0.93	2.46	0.00	0.00
	-roads	0.93	3.09	2.17	6.19	0.93	0.86	2.87	2.01
	-water supply	7.09	23.63	16.54	47.26	0.93	6.57	21.90	15.33
8	FRP supply	4.75	0.00	0.00	4.75	0.93	4.40	0.00	0.00
9	Pilot R & D Schemes	0.84	0.84	0.00	1.67	0.93	0.77	0.77	0.00

ANNEXURE 5.2.5

A. Madhuband Washery for washing prime coking coals (capacity 2.5 mt/year)

(1) Ref. No.	(2) Type of capital stock	(11) Total	(12) Life (years)	(13) CRF	(14) Annualised capital cost (Rs/tonne) (11)*(13)	(15) Running cost (Rs/tonne)	(16) Total cost of washing (Rs/tonne) (14)+(15)
1	Land	0.00	60	0.12013	0.00		
2	Buildings						
	-Residential	35.27	58	0.12017	4.24		
	-Service	236.49	58	0.12017	28.42		
3	Plant & machinery	550.96	20	0.13388	73.76		
4	Furniture	1.12	20	0.13388	0.15		
5	Railway siding	30.13	20	0.13388	4.03		
6	Vehicles	1.74	20	0.13388	0.23		
7	Development						
	-washery	2.46	20	0.13388	0.33		
	-roads	5.73	20	0.13388	0.77		
	-water supply	43.79	20	0.13388	5.86		
8	FRP supply	4.40	20	0.13388	0.59		
9	Pilot R & D Schemes	1.55	20	0.13388	0.21		
Total capital cost/year					118.59		
Cost of washing (Rs/tonne of clean coal)					108.50	64.87	173.37

Source: TERI, Coking Coal Supplies to Steel Plants - An Economic Analysis of Indigenous Supplies vis-a-vis Imported Coal, Final Report, April 1990.

ANNEXURE 5.2.5 contd...

B. Rajrappa Washery for washing medium coking coal (capacity 3 mt/year)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Ref. No.	Type of capital stock	Investment expenditure (million Rs.in Jan.1989 prices)									Price index
		Till 3/83	1983-84	1984-85	1985-86	1986-87	1987-88	1988-89	1989-90	Total (3)to(10)	
1	Land	0.63	0.45	0.08	0.06	0.14		0.92		2.28	0.93
2	Buildings										
	-Residential	10.12		0.03		0.02	0.11	2.22	1.15	13.65	0.93
	-Service	64.55	0.02	0.19	0.73	0.61	0.36	1.64	18.46	86.57	0.93
3	P & M	113.15	24.42	30.61	22.26	3.43	1.85	8.10	43.24	247.06	0.91
4	Furniture	0.20	0.01		0.09	0.26	0.01	0.02	0.79	1.37	0.93
5	Rly Siding	53.52	44.09	23.20	41.77	7.53	5.80	11.60	25.90	213.40	0.93
6	Vehicles	0.40			0.39	0.01	0.01		1.37	2.19	0.84
7	Development										
	-washery	1.73							0.63	2.36	0.93
	-roads	1.62	0.23	0.01	0.60	1.42	1.00	1.49	6.21	12.58	0.93
	-water supply	109.30	11.83	39.89	34.59	13.52	0.05	0.01	71.58	280.76	0.93
8	FRP supply	9.15				1.84			5.19	16.17	0.93

ANNEXURE 5.2.5 contd...

B. Rajrappa Washery for washing medium coking coal (capacity 3 mt/year)

(1) Ref.	(2) Type of capital stock	(13) Investment expenditure Till 3/83 (3)*(12)	(14) 1983-84 (4)*(12)	(15) 1984-85 (5)*(12)	(16) 1985-86 (6)*(12)	(17) 1986-87 (7)*(12)	(18) 1987-88 (8)*(12)	(19) 1988-89 (9)*(12)	(20) 1989-90 (10)*(12)	(21) Total (13)to(20)
1	Land	0.58	0.42	0.07	0.06	0.13	0.00	0.85	0.00	2.11
2	Buildings									
	-Residential	9.38	0.00	0.03	0.00	0.02	0.10	2.06	1.06	12.65
	-Service	59.81	0.02	0.18	0.68	0.57	0.33	1.52	17.11	80.22
3	P & M	102.61	22.15	27.76	20.18	3.11	1.68	7.34	39.21	224.05
4	Furniture	0.18	0.01	0.00	0.09	0.24	0.01	0.02	0.73	1.27
5	Rly Siding	49.59	40.85	21.50	38.70	6.97	5.38	10.75	24.00	197.74
6	Vehicles	0.34	0.00	0.00	0.33	0.01	0.01	0.00	1.15	1.84
7	Development									
	-washery	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.58	2.18
	-roads	1.50	0.21	0.01	0.56	1.31	0.93	1.38	5.76	11.66
	-water supply	101.28	10.97	36.96	32.05	12.52	0.04	0.01	66.33	260.16
8	FRP supply	8.48	0.00	0.00	0.00	1.70	0.00	0.00	4.81	14.99

ANNEXURE 5.2.5 contd...

B. Rajrappa Washery for washing medium coking coal (capacity 3 mt/year)

(million Rs.in 1987-88 prices)

(1) Ref.	(2) Type of capital stock	(13) Investment expenditure Till 3/83 (3)*(12)	(14) 1983-84 (4)*(12)	(15) 1984-85 (5)*(12)	(16) 1985-86 (6)*(12)	(17) 1986-87 (7)*(12)	(18) 1987-88 (8)*(12)	(19) 1988-89 (9)*(12)	(20) 1989-90 (10)*(12)	(21) Total
1	Land	0.58	0.42	0.07	0.06	0.13	0.00	0.85	0.00	2.11
2	Buildings									
	-Residential	9.38	0.00	0.03	0.00	0.02	0.10	2.06	1.06	[illegible]
	-Service	59.81	0.02	0.18	0.68	0.57	0.33	1.52	17.11	80.
3	P & M	102.61	22.15	27.76	20.18	3.11	1.68	7.34	39.21	224.
4	Furniture	0.18	0.01	0.00	0.09	0.24	0.01	0.02	0.73	[illegible]
5	Rly Siding	49.59	40.85	21.50	38.70	6.97	5.38	10.75	24.00	197.7
6	Vehicles	0.34	0.00	0.00	0.33	0.01	0.01	0.00	1.15	1.8
7	Development									
	-washery	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.58	2.1
	-roads	1.50	0.21	0.01	0.56	1.31	0.93	1.38	5.76	11.6
	-water supply	101.28	10.97	36.96	32.05	12.52	0.04	0.01	66.33	260.1
8	FRP supply	8.48	0.00	0.00	0.00	1.70	0.00	0.00	4.81	14.9

ANNEXURE 5.2.5 contd...

B. Rajrappa Washery for washing medium coking coal (capacity 3 mt/year)

(1) Ref.	(2) Type of capital stock	(22) Life (years)	(23) CRF	(24) Annualised capital cost (Rs/tonne) (21)*(23)	(25) Running cost (Rs/tonne)	(26) Total cost of washing (Rs/tonne) (24)+(25)
1	Land	60	0.12013	0.25		
2	Buildings					
	-Residential	58	0.12017	1.52		
	-Service	58	0.12017	9.64		
3	P & M	20	0.13388	30.00		
4	Furniture	20	0.13388	0.17		
5	Rly Siding	20	0.13388	26.47		
6	Vehicles	20	0.13388	0.25		
7	Development					
	-washery	20	0.13388	0.29		
	-roads	20	0.13388	1.56		
	-water supply	20	0.13388	34.83		
8	FRP supply	20	0.13388	2.01		
	Total capital cost/year			106.99		
	Cost of washing (Rs/tonne of clean coal)			101.18	48.78	149.96

Source: TERI, Coking Coal Supplies to Steel Plants - An Economic Analysis of Indigenous Supplies vis-a-vis Imported Coal, Final Report, April 1990.

ANNEXURE 5.2.6

Cost of manufacture of soft coke by SSF (Special Smokeless Fuel) technology

		Plant capacity 50 tpd	100 tpd	Remarks
(1)	Grade of coal	W-IV	W-IV	
(2)	Daily requirement of steam coal (tonnes)	83	168	Normative
(3)	Annual requirement of steam coal (tonnes)	29050	58800	(2)*(7)
(4)	Annual output of SSF (tonnes)	17500	35000	
(5)	Price of coal (Rs/Tonne)	287.74	287.74	As calculated for OCSD technology of mining
(6)	Total cost of coal input(Rs lakhs)	83.59	169.19	(3)*(5)*(7)
(7)	Number of working days/year	350	350	
(8)	Capital investment in 1987-88 prices (Rs.lakhs)	44.25	53.79	
(9)	CRF	0.1339	0.1339	Operating life of capital=9 years, Interest=12%
(10)	Annualised capital cost (Rs.lakhs)	5.92	7.20	(8)*(9)
(11)	Manpower (nos.)	60	106	
(12)	Daily wage bill (Rs.lakhs)	7000	7000	Considering minimum wage rate as Rs.20/ person/day
(13)	Annual wage bill (Rs.lakhs)	4.2	7.42	(7)*(12)
(14)	Annual power requirement (kWh)	315000	420000	
(15)	Economic cost of power (Rs/kWh)	1.09	1.09	As estimated for TNEB
(16)	Annual cost of power(Rs lakhs)	3.43	4.58	(14)*(15)
(17)	Annual water requirement (m^3)	9800	19250	
(18)	Cost of water (Rs/m^3)	0.70	0.70	Taken from the water bills of TERI for 1987-88
(19)	Total cost of water (Rs lakhs)	0.07	0.13	(17)*(18)
(20)	Interest on working capital (Rs.lakhs)	2.40	4.68	
(21)	Credit for coal fines(Rs/tonne)*	39.90	41.25	
(22)	Cost of soft coke (Rs/Tonne)	529.32	510.76	

* Considering that screening losses are =(1.66-1.35)/1.66 in case of a 50 tpd plant and (1.68-1.35)/1.68 in case of a 100 tpd plant.

Source: [2] in References for Chapter 5-Section 5.2

Estimation of marginal cost of supply of coking coal (for specific O-D combinations)

(1) S.No.	(2) Place of origin	(3) Destination	(5) Distance by rail (Kms)	(6) Cost of rail (in 1984-85 prices) (Rs/tonne)	(7) transport (in 1987-88 prices) (Rs/tonne)	(8) Cost of supply of PCC (Rs/tonne) 531.27+(7)	(9) Cost of washing of PCC (Rs/tonne)
1	DHANBAD	BSP	778	134.47	165.40	696.67	173.37
2	DHANBAD	RSP	292	75.32	92.64	623.91	173.37
3	DHANBAD	BSL	50	44.60	54.86	586.13	173.37
4	DHANBAD	DSP	101	52.34	64.38	595.65	173.37
5	DHANBAD	IISCO	64	48.47	59.62	590.89	173.37
6	DHANBAD	VSP	994	161.39	198.50	729.77	173.37

ANNEXURE 5.2.7 contd...

Estimation of marginal cost of supply of coking coal (for specific O-D combinations)

(1) S.No.	(2) Place of origin	(3) Destination	(10) Credit for middlings (Rs/tonne) 150*0.4150	(11) Net cost of supply of PCC (Rs/tonne) (8)+(9)-(10)	(12) Cost of supply of MCC (Rs/tonne) 289.67+(7)	(13) Cost of washing of MCC (Rs/tonne)	(14) Credit for middlings (Rs/tonne) 150*0.6185	(15) Net cost of supply of MCC (Rs/tonne) (12)+(13)-(14)
1	DHANBAD	BSP	62.25	807.78	455.07	150.20	92.77	754.10
2	DHANBAD	RSP	62.25	735.03	382.31	150.20	92.77	681.34
3	DHANBAD	BSL	62.25	697.24	344.53	150.20	92.77	643.56
4	DHANBAD	DSP	62.25	706.76	354.05	150.20	92.77	653.08
5	DHANBAD	IISCO	62.25	702.00	349.29	150.20	92.77	648.32
6	DHANBAD	VSP	62.25	840.89	488.17	150.20	92.77	787.20

ANNEXURE 5.2.7

Estimation of marginal cost of supply of coal and soft coke (by distance slabs)

(1) Ref. no.	(2) Distance slab (Kms.)	(3) Cost of transportation (Rs/Tonne)	(4) Total cost of supply in 1987-88 prices: Non-coking* coal (Rs/Tonne) 192.97+(3)	(5) Coking coals PCC (Rs/Tonne) 642.39+(3)	(6) Coking coals MCC (Rs/Tonne) 347.66+(3)	(7) Soft coke** (Rs/Tonne) 192.97+(3)
1	RAIL					
	BGDL-BL-PLAINS					
	Upto 250	66.52	259.49	708.91	414.18	586.56
	250-500	107.61	300.58	749.99	455.27	627.65
	500-750	140.70	333.67	783.09	488.36	660.74
	750-1000	176.39	369.36	818.78	524.05	696.43
	1000-1250	220.09	413.06	862.48	567.75	740.13
	1250-1500	266.97	459.94	909.36	614.63	787.01
	1500-1750	303.20	496.16	945.58	650.86	823.24
	1750-2000	339.42	532.39	981.80	687.08	859.46
	2000-2250	375.64	568.61	1018.03	723.30	895.68
	2250-2500	411.87	604.83	1054.25	759.53	931.91
	2500-2750	448.09	641.06	1090.48	795.75	968.13
	2750-3000	484.31	677.28	1126.70	831.97	1004.35
2	ROAD					
	NHDL-PLAINS					
	Upto 250	59.58	252.55	701.97	407.24	579.62
	250-500	128.44	321.41	770.82	476.10	648.48
	500-750	192.54	385.50	834.92	540.20	712.58
	750-1000	250.98	443.95	893.37	598.64	771.02
	1000-1250	328.51	521.48	970.90	676.17	848.55
	1250-1500	414.83	607.80	1057.21	762.49	934.87
	1500-1750	480.34	673.31	1122.73	828.00	1000.38
	1750-2000	545.85	738.82	1188.24	893.51	1065.89
	2000-2250	611.37	804.33	1253.75	959.03	1131.41
	2250-2500	676.87	869.84	1319.26	1024.53	1196.91
	2500-2750	742.39	935.36	1384.77	1090.05	1262.43
	2750-3000	807.89	1000.86	1450.28	1155.55	1327.93
3	COASTAL					
	1000-1250	211.84	404.81	854.23	559.50	731.88
	1250-1500	217.20	410.17	859.58	564.86	737.24
	1500-1750	227.93	420.90	870.31	575.59	747.97
	1750-2000	222.56	415.53	864.94	570.22	742.60
	2000-2250	233.28	426.24	875.66	580.94	753.32
	2250-2500	238.64	431.60	881.02	586.30	758.68
	2500-2750	243.99	436.96	886.38	591.65	764.03
	2750-3000	249.35	442.32	891.74	597.01	769.39

* Assuming the share of OCDL, OCSD and UGBP to be 32.5%, 32.5% and 35% repectively.

** Using W-IV coking coal as input.

Annexure 5.2.7

Estimation of marginal cost of supply of non-coking coal & soft coke (for specific O-D combinations)

(1) S.No.	(2) Place of origin	(3) State of origin	(4) Destination	(5) Distance by rail (Kms)	(6) Cost of rail transport (Rs/tonne)	(7) Distance by coast (Kms)	(8) Cost of coastal shipping (Rs/tonne)	(9) Total distance (Kms)	(10) Total cost of transport in 1984-85 (Rs/tonne) (6)+(8)
1	Dorkanal	AP	Delhi	1636	231.78			1636	231.78
2	Nagpur	Maharashtra	Delhi	1095	170.42			1095	170.42
3	Amla	MP	Delhi	927	152.35			927	152.35
4	Anuppur	MP	Delhi	997	161.39			997	161.39
5	Singrauli	MP	Delhi	923	152.35			923	152.35
6	Talcher	Orrisa	Delhi	1778	246.50			1778	246.50
7	Jharsuguda	Orrisa	Delhi	1354	202.35			1354	202.35
8	Karanji	MP	Delhi	1142	179.04			1142	179.04
9	Korba	MP	Delhi	1237	187.65			1237	187.65
10	Daltonganj	Bihar	Delhi	1030	161.39			1030	161.39
11	Barbakana	Bihar	Delhi	1215	187.65			1215	187.65
12	Dhanbad	Bihar	Delhi	1182	179.04			1182	179.04
13	Pirpainti	Bihar	Delhi	1163	179.04			1163	179.04
1	Dorkanal	AP	Bombay	559	131.27	2691	241.31	3250	372.59
2	Nagpur	Maharashtra	Bombay	835	134.47			835	134.47
3	Amla	MP	Bombay	873	143.41			873	143.41
4	Anuppur	MP	Bombay	790	165.40	3161	262.74	3951	428.13
5	Singrauli	MP	Bombay	1340	202.35			1340	202.35
6	Talcher	Orrisa	Bombay	198	53.90	3450	286.76	3648	340.66
7	Jharsuguda	Orrisa	Bombay	408	107.56	3450	286.76	3858	394.32
8	Karanji	MP	Bombay	935	187.39	3161	262.74	4096	450.13
9	Korba	MP	Bombay	599	131.27	3450	286.76	4049	418.03
10	Daltonganj	Bihar	Bombay	586	131.27	3565	296.32	4151	427.59
11	Barbakana	Bihar	Bombay	401	107.56	3565	296.32	3966	403.88
12	Dhanbad	Bihar	Bombay	383	104.16	3565	296.32	3948	400.47
13	Pirpainti	Bihar	Bombay	502	121.95	3565	296.32	4067	418.27
1	Dorkanal	AP	Madras	559	106.73			559	106.73
2	Nagpur	Maharashtra	Madras	1100	170.42			1100	170.42
3	Amla	MP	Madras	1268	187.65			1268	187.65
4	Anuppur	MP	Madras	1664	231.78			1664	231.78
5	Singrauli	MP	Madras	1995	275.95			1995	275.95
6	Talcher	Orrisa	Madras	198	53.90	946	164.20	1144	218.10
7	Jharsuguda	Orrisa	Madras	408	107.56	946	164.20	1354	271.76
8	Karanji	MP	Madras	1809	261.23			1809	261.23
9	Korba	MP	Madras	1602	231.78			1602	231.78
10	Daltonganj	Bihar	Madras	1924	275.95			1924	275.95
11	Barbakana	Bihar	Madras	1739	246.50			1739	246.50
12	Dhanbad	Bihar	Madras	1784	246.50			1784	246.50
13	Pirpainti	Bihar	Madras	2113	290.68			2113	290.68
1	Dorkanal	AP	Calcutta	1696	231.78			1696	231.78
2	Nagpur	Maharashtra	Calcutta	1155	179.04			1155	179.04
3	Amla	MP	Calcutta	1323	202.35			1323	202.35
4	Anuppur	MP	Calcutta	893	143.41			893	143.41
5	Singrauli	MP	Calcutta	850	143.41			850	143.41
6	Talcher	Orrisa	Calcutta	501	99.15			501	99.15
7	Jharsuguda	Orrisa	Calcutta	536	99.15			536	99.15
8	Karanji	MP	Calcutta	1038	161.39			1038	161.39
9	Korba	MP	Calcutta	727	124.43			727	124.43
10	Daltonganj	Bihar	Calcutta	574	106.73			574	106.73
11	Barbakana	Bihar	Calcutta	389	87.45			389	87.45
12	Dhanbad	Bihar	Calcutta	259	69.57			259	69.57
13	Pirpainti	Bihar	Calcutta	337	81.91			337	81.91

Estimation of marginal cost of supply of non-coking coal & soft coke (for specific O-D combinations)

(1) S.No.	(2) Place of origin	(3) State of origin	(4) Destination	(11) Total cost of production in 1987-88 prices Non-coking coal OCDL (Rs/tonne) 156.52+(11)	(12) OCSD (Rs/tonne) 157.13+(11)	(13) UGBP (Rs/tonne) 260.09+(11)	(14) Softcoke (from W-IV) 50tpd (Rs/tonne) 529.32+(11)	(15) 100tpd (Rs/tonne) 510.76+(11)	(16) Total cost of supply in 1987-88 prices (Rs/tonne)
1	Dorkanal	AP	Delhi	285.08	441.60	442.21	545.17	814.40	795.84
2	Nagpur	Maharashtra	Delhi	209.62	366.14	366.75	469.71	738.94	720.38
3	Amla	MP	Delhi	187.39	343.91	344.52	447.48	716.71	698.15
4	Anuppur	MP	Delhi	198.50	355.02	355.63	458.59	727.82	709.26
5	Singrauli	MP	Delhi	187.39	343.91	344.52	447.48	716.71	698.15
6	Talcher	Orrisa	Delhi	303.20	459.72	460.33	563.29	832.52	813.96
7	Jharsuguda	Orrisa	Delhi	248.89	405.41	406.02	508.98	778.21	759.65
8	Karanji	MP	Delhi	220.21	376.73	377.34	480.30	749.53	730.97
9	Korba	MP	Delhi	230.81	387.33	387.94	490.90	760.13	741.57
10	Daltonganj	Bihar	Delhi	198.50	355.02	355.63	458.59	727.82	709.26
11	Barbakana	Bihar	Delhi	230.81	387.33	387.94	490.90	760.13	741.57
12	Dhanbad	Bihar	Delhi	220.21	376.73	377.34	480.30	749.53	730.97
13	Pirpainti	Bihar	Delhi	220.21	376.73	377.34	480.30	749.53	730.97
1	Dorkanal	AP	Bombay	372.59	529.11	529.72	632.68	901.91	883.35
2	Nagpur	Maharashtra	Bombay	165.40	321.92	322.53	425.49	694.72	676.16
3	Amla	MP	Bombay	176.39	332.91	333.52	436.48	705.71	687.15
4	Anuppur	MP	Bombay	428.13	584.65	585.26	688.22	957.45	938.89
5	Singrauli	MP	Bombay	248.89	405.41	406.02	508.98	778.21	759.65
6	Talcher	Orrisa	Bombay	340.66	497.18	497.79	600.75	869.98	851.42
7	Jharsuguda	Orrisa	Bombay	394.32	550.84	551.45	654.41	923.64	905.08
8	Karanji	MP	Bombay	450.13	606.65	607.26	710.22	979.45	960.89
9	Korba	MP	Bombay	418.03	574.55	575.16	678.12	947.35	928.79
10	Daltonganj	Bihar	Bombay	427.59	584.11	584.72	687.68	956.91	938.35
11	Barbakana	Bihar	Bombay	403.88	560.40	561.01	663.97	933.20	914.64
12	Dhanbad	Bihar	Bombay	400.47	556.99	557.60	660.56	929.79	911.23
13	Pirpainti	Bihar	Bombay	418.27	574.79	575.40	678.36	947.59	929.03
1	Dorkanal	AP	Madras	131.27	287.79	288.40	391.36	660.59	642.03
2	Nagpur	Maharashtra	Madras	209.62	366.14	366.75	469.71	738.94	720.38
3	Amla	MP	Madras	230.81	387.33	387.94	490.90	760.13	741.57
4	Anuppur	MP	Madras	285.08	441.60	442.21	545.17	814.40	795.84
5	Singrauli	MP	Madras	339.42	495.94	496.55	599.51	868.74	850.18
6	Talcher	Orrisa	Madras	218.10	374.62	375.23	478.19	747.42	728.86
7	Jharsuguda	Orrisa	Madras	271.76	428.28	428.89	531.85	801.08	782.52
8	Karanji	MP	Madras	321.31	477.83	478.44	581.40	850.63	832.07
9	Korba	MP	Madras	285.08	441.60	442.21	545.17	814.40	795.84
10	Daltonganj	Bihar	Madras	339.42	495.94	496.55	599.51	868.74	850.18
11	Barbakana	Bihar	Madras	303.20	459.72	460.33	563.29	832.52	813.96
12	Dhanbad	Bihar	Madras	303.20	459.72	460.33	563.29	832.52	813.96
13	Pirpainti	Bihar	Madras	357.53	514.05	514.66	617.62	886.85	868.29
1	Dorkanal	AP	Calcutta	285.08	441.60	442.21	545.17	814.40	795.84
2	Nagpur	Maharashtra	Calcutta	220.21	376.73	377.34	480.30	749.53	730.97
3	Amla	MP	Calcutta	248.89	405.41	406.02	508.98	778.21	759.65
4	Anuppur	MP	Calcutta	176.39	332.91	333.52	436.48	705.71	687.15
5	Singrauli	MP	Calcutta	176.39	332.91	333.52	436.48	705.71	687.15
6	Talcher	Orrisa	Calcutta	121.95	278.47	279.08	382.04	651.27	632.71
7	Jharsuguda	Orrisa	Calcutta	121.95	278.47	279.08	382.04	651.27	632.71
8	Karanji	MP	Calcutta	198.50	355.02	355.63	458.59	727.82	709.26
9	Korba	MP	Calcutta	153.05	309.57	310.18	413.14	682.37	663.81
10	Daltonganj	Bihar	Calcutta	131.27	287.79	288.40	391.36	660.59	642.03
11	Barbakana	Bihar	Calcutta	107.56	264.08	264.69	367.65	636.88	618.32
12	Dhanbad	Bihar	Calcutta	85.57	242.09	242.70	345.66	614.89	596.33
13	Pirpainti	Bihar	Calcutta	100.75	257.27	257.88	360.84	630.07	611.51

Annexure 5.2.8

Rates of Royalty for all states: Notification No:21(5)/79-CL dt. 12.02.81 w.e.f. 13.02.81

Coking		Non-coking	
Grade	Rs/Tonne	Grade	Rs/Tonne
Steel-I	7.00	A	6.50
Steel-II	7.00	B	6.50
Washery-I	7.00	C	5.50
Washery-II	6.50	D	4.30
Washery-III	6.50	E	4.30
Washery-IV	6.50	F	2.50
S.Coking-I	6.50	G	2.50
S.Coking-II	6.50	Assam	6.50

Stowing Excise Duty (Rs/Tonne)

Coking	4.25	Non-coking	3.50

State wise levies(Cesses)

a) West Bengal	
1. Rural employment & production cess	35% on pithead price
2. Primary education cess	5% on pithead price
3. Public works & road cess	Rs 1/Tonne
4. Assansole Mines Board Health Cess	Rs 0.40/Tonne
b) Bihar	
1. Cess on royalty	40% on pithead price
2. Royalty & cess	5% on royalty
3. Jharia Mines Board Health Cess	Rs 3.50/Tonne
4. Jharia Water Board	Rs 0.10/Tonne (BCCL only)
c) Orissa	
1. Mines area development cess	30% on royalty (wef 26.10.88) 30% on pithead price (wef 14.(
d) Madhya Pradesh	
1. Mineral area development cess	125% on royalty
2. Storaged cess	Rs 5.00/Tonne
3. Sada	Nil
e) Maharashtra	
1. Cess on royalty	10% on royalty

Sales tax

4% sales tax is charged on coal values as well as on royalties and levies subject to the submission of the "C" form.

Source: CIL, Calcutta.

Annexure 5.2.9 contd..

Estimation of market price of non-coking coal and soft-coke (for specific O-D combinations)

(1) S.No.	(2) Place of origin	(3) State of origin	(4) Destination	(5) Total distance (Kms)	(6) Cost of transportation for power @Rs 0.261 per TKms (Rs/tonne) 0.261*(5)	(7) for others @Rs 0.255 per TKms (Rs/tonne) 0.255*(5)	(8) Price of grade-D (excl.levies) CIL 212 SCCL 295.5 (Rs/tonne) 212 or 295.5+(6)
1	Dorkanal	AP	Delhi	1636	427.0	417.2	722.5
2	Nagpur	Maharashtra	Delhi	1095	285.8	279.2	497.8
3	Amla	MP	Delhi	927	241.9	236.4	453.9
4	Anuppur	MP	Delhi	997	260.2	254.2	472.2
5	Singrauli	MP	Delhi	923	240.9	235.4	452.9
6	Talcher	Orrisa	Delhi	1778	464.1	453.4	676.1
7	Jharsuguda	Orrisa	Delhi	1354	353.4	345.3	565.4
8	Karanji	MP	Delhi	1142	298.1	291.2	510.1
9	Korba	MP	Delhi	1237	322.9	315.4	534.9
10	Daltonganj	Bihar	Delhi	1030	268.8	262.7	480.8
11	Barbakana	Bihar	Delhi	1215	317.1	309.8	529.1
12	Dhanbad	Bihar	Delhi	1182	308.5	301.4	520.5
13	Pirpainti	Bihar	Delhi	1163	303.5	296.6	515.5
1	Dorkanal	AP	Bombay	3250	848.3	828.8	1143.8
2	Nagpur	Maharashtra	Bombay	835	217.9	212.9	429.9
3	Amla	MP	Bombay	873	227.9	222.6	439.9
4	Anuppur	MP	Bombay	3951	1031.2	1007.5	1243.2
5	Singrauli	MP	Bombay	1340	349.7	341.7	561.7
6	Talcher	Orrisa	Bombay	3648	952.1	930.2	1164.1
7	Jharsuguda	Orrisa	Bombay	3858	1006.9	983.8	1218.9
8	Karanji	MP	Bombay	4096	1069.1	1044.5	1281.1
9	Korba	MP	Bombay	4049	1056.8	1032.5	1268.8
10	Daltonganj	Bihar	Bombay	4151	1083.4	1058.5	1295.4
11	Barbakana	Bihar	Bombay	3966	1035.1	1011.3	1247.1
12	Dhanbad	Bihar	Bombay	3948	1030.4	1006.7	1242.4
13	Pirpainti	Bihar	Bombay	4067	1061.5	1037.1	1273.5
1	Dorkanal	AP	Madras	559	145.9	142.5	441.4
2	Nagpur	Maharashtra	Madras	1100	287.1	280.5	499.1
3	Amla	MP	Madras	1268	330.9	323.3	542.9
4	Anuppur	MP	Madras	1664	434.3	424.3	646.3
5	Singrauli	MP	Madras	1995	520.7	508.7	732.7
6	Talcher	Orrisa	Madras	1144	298.6	291.7	510.6
7	Jharsuguda	Orrisa	Madras	1354	353.4	345.3	565.4
8	Karanji	MP	Madras	1809	472.1	461.3	684.1
9	Korba	MP	Madras	1602	418.1	408.5	630.1
10	Daltonganj	Bihar	Madras	1924	502.2	490.6	714.2
11	Barbakana	Bihar	Madras	1739	453.9	443.4	665.9
12	Dhanbad	Bihar	Madras	1784	465.6	454.9	677.6
13	Pirpainti	Bihar	Madras	2113	551.5	538.8	763.5
1	Dorkanal	AP	Calcutta	1696	442.7	432.5	738.2
2	Nagpur	Maharashtra	Calcutta	1155	301.5	294.5	513.5
3	Amla	MP	Calcutta	1323	345.3	337.4	557.3
4	Anuppur	MP	Calcutta	893	233.1	227.7	445.1
5	Singrauli	MP	Calcutta	850	221.9	216.8	433.9
6	Talcher	Orrisa	Calcutta	501	130.8	127.8	342.8
7	Jharsuguda	Orrisa	Calcutta	536	139.9	136.7	351.9
8	Karanji	MP	Calcutta	1038	270.9	264.7	482.9
9	Korba	MP	Calcutta	727	189.7	185.4	401.7
10	Daltonganj	Bihar	Calcutta	574	149.8	146.4	361.8
11	Barbakana	Bihar	Calcutta	389	101.5	99.2	313.5
12	Dhanbad	Bihar	Calcutta	259	67.6	66.0	279.6
13	Pirpainti	Bihar	Calcutta	337	88.0	85.9	300.0

Annexure 5.2.9

Estimation of market price of non-coking coal and soft-coke (for specific O-D combinations)

(1) S.No.	(2) Place of origin	(3) State of origin	(4) Destination	(9) Royalty	(10) Cesses	(11) Excise tax	(12) Sales tax	(13) Total cost of supply(incl.levi Grade-D (Rs/tonne) (8)to(12)	(14) Soft coke (Rs/tonne) 175+(7)
1	Dorkanal	AP	Delhi	4.3	0.4	3.5	8.5	739.2	592.2
2	Nagpur	Maharashtra	Delhi	4.3	0.4	3.5	8.5	514.5	454.2
3	Amla	MP	Delhi	4.3	10.4	3.5	8.5	480.6	411.4
4	Anuppur	MP	Delhi	4.3	10.4	3.5	8.5	498.9	429.2
5	Singrauli	MP	Delhi	4.3	10.4	3.5	8.5	479.6	410.4
6	Talcher	Orrisa	Delhi	4.3	88.5	3.5	8.5	780.9	628.4
7	Jharsuguda	Orrisa	Delhi	4.3	88.5	3.5	8.5	670.2	520.3
8	Karanji	MP	Delhi	4.3	10.4	3.5	8.5	536.7	466.2
9	Korba	MP	Delhi	4.3	10.4	3.5	8.5	561.5	490.4
10	Daltonganj	Bihar	Delhi	4.3	88.5	3.5	8.5	585.6	437.7
11	Barbakana	Bihar	Delhi	4.3	88.5	3.5	8.5	633.9	484.8
12	Dhanbad	Bihar	Delhi	4.3	88.5	3.5	8.5	625.3	476.4
13	Pirpainti	Bihar	Delhi	4.3	88.5	3.5	8.5	620.3	471.6
1	Dorkanal	AP	Bombay	4.3	0.4	3.5	8.5	1160.5	1003.8
2	Nagpur	Maharashtra	Bombay	4.3	0.4	3.5	8.5	446.6	387.9
3	Amla	MP	Bombay	4.3	10.4	3.5	8.5	466.5	397.6
4	Anuppur	MP	Bombay	4.3	10.4	3.5	8.5	1269.9	1182.5
5	Singrauli	MP	Bombay	4.3	10.4	3.5	8.5	588.4	516.7
6	Talcher	Orrisa	Bombay	4.3	88.5	3.5	8.5	1268.9	1105.2
7	Jharsuguda	Orrisa	Bombay	4.3	88.5	3.5	8.5	1323.7	1158.8
8	Karanji	MP	Bombay	4.3	10.4	3.5	8.5	1307.7	1219.5
9	Korba	MP	Bombay	4.3	10.4	3.5	8.5	1295.4	1207.5
10	Daltonganj	Bihar	Bombay	4.3	88.5	3.5	8.5	1400.2	1233.5
11	Barbakana	Bihar	Bombay	4.3	88.5	3.5	8.5	1351.9	1186.3
12	Dhanbad	Bihar	Bombay	4.3	88.5	3.5	8.5	1347.2	1181.7
13	Pirpainti	Bihar	Bombay	4.3	88.5	3.5	8.5	1378.3	1212.1
1	Dorkanal	AP	Madras	4.3	0.4	3.5	8.5	458.1	317.5
2	Nagpur	Maharashtra	Madras	4.3	0.4	3.5	8.5	515.8	455.5
3	Amla	MP	Madras	4.3	10.4	3.5	8.5	569.6	498.3
4	Anuppur	MP	Madras	4.3	10.4	3.5	8.5	673.0	599.3
5	Singrauli	MP	Madras	4.3	10.4	3.5	8.5	759.4	683.7
6	Talcher	Orrisa	Madras	4.3	88.5	3.5	8.5	615.4	466.7
7	Jharsuguda	Orrisa	Madras	4.3	88.5	3.5	8.5	670.2	520.3
8	Karanji	MP	Madras	4.3	10.4	3.5	8.5	710.8	636.3
9	Korba	MP	Madras	4.3	10.4	3.5	8.5	656.8	583.5
10	Daltonganj	Bihar	Madras	4.3	88.5	3.5	8.5	819.0	665.6
11	Barbakana	Bihar	Madras	4.3	88.5	3.5	8.5	770.7	618.4
12	Dhanbad	Bihar	Madras	4.3	88.5	3.5	8.5	782.4	629.9
13	Pirpainti	Bihar	Madras	4.3	88.5	3.5	8.5	868.3	713.8
1	Dorkanal	AP	Calcutta	4.3	0.4	3.5	8.5	754.9	607.5
2	Nagpur	Maharashtra	Calcutta	4.3	0.4	3.5	8.5	530.2	469.5
3	Amla	MP	Calcutta	4.3	10.4	3.5	8.5	584.0	512.4
4	Anuppur	MP	Calcutta	4.3	10.4	3.5	8.5	471.7	402.7
5	Singrauli	MP	Calcutta	4.3	10.4	3.5	8.5	460.5	391.8
6	Talcher	Orrisa	Calcutta	4.3	88.5	3.5	8.5	447.6	302.8
7	Jharsuguda	Orrisa	Calcutta	4.3	88.5	3.5	8.5	456.7	311.7
8	Karanji	MP	Calcutta	4.3	10.4	3.5	8.5	509.6	439.7
9	Korba	MP	Calcutta	4.3	10.4	3.5	8.5	428.4	360.4
10	Daltonganj	Bihar	Calcutta	4.3	88.5	3.5	8.5	466.6	321.4
11	Barbakana	Bihar	Calcutta	4.3	88.5	3.5	8.5	418.3	274.2
12	Dhanbad	Bihar	Calcutta	4.3	88.5	3.5	8.5	384.4	241.0
13	Pirpainti	Bihar	Calcutta	4.3	88.5	3.5	8.5	404.8	260.9

Annexure 5.2.9

Estimation of market price of coals and soft-coke (by distance slabs)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Cost of supply (Rs/tonne)				
Distance slab	Cost of transportation @ Rs .26/TKMS (Rs/tonne)	NCC Grade D 316.8+(2)	Soft-coke 175+(2)	NCC from CCL 651.9+(2)	Coking coal PCC CCHO 709.3+(2)	PCC 670+(2)
250	64.5	381.3	239.5	716.4	773.8	734.5
500	129.0	445.8	304.0	780.9	838.3	799.0
750	193.5	510.3	368.5	845.4	902.8	863.5
1000	258.0	574.8	433.0	909.9	967.3	928.0
1250	322.5	639.3	497.5	974.4	1031.8	992.5
1500	387.0	703.8	562.0	1038.9	1096.3	1057.0
1750	451.5	768.3	626.5	1103.4	1160.8	1121.5
2000	516.0	832.8	691.0	1167.9	1225.3	1186.0
2250	580.5	897.3	755.5	1232.4	1289.8	1250.5
2500	645.0	961.8	820.0	1296.9	1354.3	1315.0
2750	709.5	1026.3	884.5	1361.4	1418.8	1379.5
3000	774.0	1090.8	949.0	1425.9	1483.3	1444.0

Annexure 5.3.1

Expenditure phasing norm

Thermal Power Project

Capacity	Phasing norm							
1x200 MW	1%	10%	16%	30%	30%	8%	5%	-	-
2x200 MW	1%	10%	15%	25%	25%	15%	6%	3%	-
3x200 MW	10%	10%	15%	25%	25%	15%	6%	3%	-
4x200 MW	1%	9%	12%	20%	28%	18%	7%	3%	2%
5x200 MW	1%	9%	12%	20%	28%	11%	7%	3%	2%
1x500 MW	1%	8%	12%	25%	25%	15%	10%	4%	-
2x500 MW	1%	8%	12%	20%	25%	15%	10%	6%	3%
3x500 MW	1%	8%	12%	20%	25%	15%	10%	6%	3%
4x500 MW	1%	7%	10%	15%	20%	15%	7%	3%	2%
5x500 MW	1%	9%	11%	15%	20%	12%	7%	3%	2%

The first unit is installed in 5 years and each consecutive unit is installed in 6 months after the previous one.

Hydro Power Plants

Construction period	Phasing norm										
3 years	5%	25%	50%	20%	-	-	-	-	-	-	-
4 years	5%	20%	30%	30%	15%	-	-	-	-	-	-
5 years	5%	10%	25%	30%	20%	10%	-	-	-	-	-
6 years	4%	10%	15%	25%	25%	13%	8%	-	-	-	-
7 years	4%	7%	13%	15%	22%	20%	12%	7%	-	-	-
8 years	4%	5%	13%	15%	20%	20%	10%	8%	5%	-	-
9 years	3%	4%	7%	12%	15%	18%	18%	10%	8%	5%	-
10 years	3%	4%	6%	10%	15%	20%	13%	10%	8%	7%	3%
11 years	3%	3%	4%	6%	10%	14%	19%	14%	10%	8%	6%

Small/mini/macro hydle upto 15 MW take 3 years for completion. Medium and major hydro projects above 15 MW take 5 to 7 years and the large hydro projects take 6-10 years for completion.

Gas Turbines

Voltage level	Phasing norm				
3x25 MW*	10%	65%	20%	5%	
4x100 MW**	10%	25%	45%	20%	9%
2x100 MW					

* The first unit is installed in 2 years and each subsequent unit is installed after 2 months.

** The first unit is installed in 3 years and each subsequent unit is installed after 4 months.

Transmission and distribution

Voltage level	Phasing norm				
400 kV	10%	30%	40%	10%	10%
220 kV	10%	40%	40%	10%	
132 kV	30%	60%	10%		
66 kV	30%	60%	20%		

Annexure 5.3.2

Specific coal consumption of thermal power plants (1988-89)

State	Name of Power plant	Specific coal consumption (kg/kWh)
Haryana	Faridabad	0.93
	Panipat	0.74
Gujarat	Ukai	0.60
	Wankabori	0.63
Madhya Pradesh	Korba (E)	0.94
	Korba (W)	0.80
	Amarkantak	0.74
	Satpura	0.79
	Korba STPS	0.69
Maharashtra	Paras	0.78
	Khaperkheda	1.09
	Nasik	0.70
	Parli	0.63
	Koradi	0.76
	Chandrapur	0.82
	Bhusawal	0.70
Tamil Nadu	Mettur	0.74
	Ennore	0.93
	Tuticorin	0.61

Annexure 5.3.3

T & D Losses calculations at different voltage levels

Assumption:

Currents flowing through the different transmission levels are proportional to the transformation ratio of different voltage levels. Losses at different voltage levels have been calculated in terms of the length of the transmission lines, resistance of the lines and total losses.

Equation:

$$S = (1/L_{220})^{*} \quad (0.1148\ l_{440} + l_{220} + 1.84\ l_{132} + 1.03\ l_{66} + 1.425\ l_{33} + 0.6944\ l_{11})$$

$$L_{440} = \frac{0.1148 * l_{440} * Tl}{l_{220}\ S}$$

$$l_{220} = \frac{1}{S} * Tl$$

$$l_{132} = \frac{1.84\ l_{132}}{l_{220} * S} * Tl$$

$$l_{66} = \frac{1.425\ l_{33}}{l_{220} * S} * Tl$$

$$l_{11} = \frac{0.6944\ l_{11}}{l_{220} * S} * Tl$$

where,

l_{440} = total length of 440 KV lines
l_{220} = total length of 220 KV lines
l_{132} = total length of 132 KV lines
l_{66} = total length of 66 KV lines
l_{11} = total length of 11 KV lines
Tl = total T&D loss in the system
l_{440} = loss at 440 KV
l_{220} = loss at 220 KV
l_{132} = loss at 132 KV
l_{66} = loss at 66 KV
l_{11} = loss at 11 KV

Annexure 5.3.3 (Cont...)

Calculation

SEB	Total loss (%)	Loss at EHT & HT (%)	Loss at LT (%)
HSEB	21.50	16.54	4.96
GEB	19.50	14.81	4.69
MPEB	19.00	12.70	6.30
MSEB	14.40	10.13	4.27
TNEB	18.50	14.20	4.30

Annexure 5.3.4

Schedule of capacity addition by HSEB and Central sector (1988-2000)

Project Name	Total capacity (MW)	HSEB's share (%)	Schedule of capacity addition 88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
HYDRO														
Dadupur	4*2.5	100.00							10					
WYC Canal stg 2	2*8	100.00							16					
Salal (C/S)	3*115+2*115	6.08						35						
Chamera (C/S)	3*180	3.89					21							
Dhulhasti (C/S)	3*130	10.00							39					
Tanakpur (C/S)	3*40	10.00				12								
Chamera (C/S)	3*100	3.89								11.66				
Tehri (C/S)	4*250	12.57									62.85	62,85		
Napthajhakri (C/S)	6*250	12.57									62.85	62.85	62.85	
Uri (C/S)	4*120	12.57								30.17	30.17			
Samalkota (C/S)	3*200	12.57												75.42
Baghiliar (C/S)	3*150	12.57									56.57			
Kolhdam (C/S)	4*200	12.57										50.28	50.28	
Tehri 2 PSS (C/S)	4*250	12.57												125.7
Dhauliganga (C/S)	4*70	12.57									17.60	17.60		
Koteshwar (C/S)	4*100	12.57											50.28	
Karchan Wangtoo (C/S)	4*150	12.57											75.42	
Nibra (C/S)	4*60	12.57												30.17
Baspa (C/S)	4*75	12.57											18.86	18.86
Bursar (C/S)	6*170	12.57											64.11	64.11
Kishanganga (C/S)	4*100	12.57												50.28
THERMAL			210											
Panipat IV	1*210	100.00						210						
Hissar	2*250	100.00							250	250				
Rihand (C/S)	2*500	6.50						32.5	32.5					
NCTPP	4*210	10.00				21	42	21						
Yamunanagar (C/S)	2*210	41.43							174					
Birsingar Lignite (C/S)	2*210	5.71						12	12					
Rihand (C/S)	2*500	6.50								32.5	32.5			
Yamunanagar (C/S)	2*210	41.43								17'				
GAS TURBINES														
Dadri (C/S)	4*131.3+2*146	10.00				53	29							
Faridabad (C/S)	4*130+2*140	19.00					99	53						
Anta ([illegible]	3*100+1*30	8.14				22	13							

Schedule of capacity addition by HSEB and central sector (1988-2000)

Project Name	Total capacity (MW)	HSEB's share (%)	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
HYDRO														
Dadupur	4*2.5	100.00							10					
WYC Canal stg 2	2*8	100.00							16					
Salal (C/S)	3*115+2*115	6.00						35						
Chamera (C/S)	3*180	3.89					21							
Dhulhasti (C/S)	3*130	10.00							39					
Tanakpur (C/S)	3*40	10.00				12								
Chamera (C/S)	3*100	3.89								11.66				
Tehri (C/S)	4*250	12.57									62.85	62.85		
Napthajhakri (C/S)	6*250	12.57									62.85	62.85	62.85	
Uri (C/S)	4*120	12.57								30.17	30.17			
Sawalkota (C/S)	3*200	12.57												75.42
Baghiliar (C/S)	3*150	12.57									56.57			
Kolbdam (C/S)	4*200	12.57										50.28	50.28	
Tehri 2 PSS (C/S)	4*250	12.57												125.7
Dhauliganga (C/S)	4*70	12.57									17.60	17.60		
Koteshwar (C/S)	4*100	12.57											50.28	
Karcham Wangtoo (C/S)	4*150	12.57											75.42	
Nibra (C/S)	4*60	12.57												30.17
Baspa (C/S)	4*75	12.57											18.86	18.86
Dursar (C/S)	6*170	12.57											64.11	64.11
Kishanganga (C/S)	4*100	12.57												50.28
THERMAL			210											
Panipat IV	1*210	100.00						210						
Hissar	2*250	100.00							250	250				
Rihand (C/S)	2*500	6.50						32.5	32.5					
NCTPP	4*210	10.00				21	42	21						
Yamunanagar (C/S)	2*210	41.43							174					
Birsingar Lignite (C/S)	2*210	5.71						12	12					
Rihand (C/S)	2*500	6.50								32.5	32.5			
Yamunanagar (C/S)	2*210	41.43								174				
GAS TURBINES														
Dadri (C/S)	4*131.3+2*146	10.00				53	29							
Faridabad (C/S)	4*130+2*140	19.00					99	53						
Anta (C/S)	3*100+1*30	8.14				22	13							

Annexure 5.3.4

Schedule of capacity addition by HSEB and Central sector (1988-2000)

Project Name	Total capacity (MW)	HSEB's share (%)	Schedule of capacity addition 88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
HYDRO														
Badupur	4*2.5	100.00							10					
WYC Canal stg 2	2*8	100.00							16					
Salal (C/S)	3*115+2*115	6.00						35						
Chamera (C/S)	3*180	3.89					21							
Dhulhasti (C/S)	3*130	10.00							39					
Tanakpur (C/S)	3*40	10.00				12								
Chamera (C/S)	3*100	3.89								11.66				
Tehri (C/S)	4*250	12.57									62.85	62.85		
Napthajhakri (C/S)	6*250	12.57									62.85	62.85	62.85	
Uri (C/S)	4*120	12.57								30.17	30.17			
Sawalkota (C/S)	3*200	12.57												75.42
Baghiliar (C/S)	3*150	12.57									56.57			
Kolhdam (C/S)	4*200	12.57										50.28	50.28	
Tehri 2 PSS (C/S)	4*250	12.57												125.7
Dhauliganga (C/S)	4*70	12.57									17.60	17.60		
Koteshwar (C/S)	4*100	12.57											50.28	
Karcham Wangtoo (C/S)	4*150	12.57											75.42	
Nibra (C/S)	4*60	12.57												30.17
Baspa (C/S)	4*75	12.57											10.86	10.86
Bursar (C/S)	6*170	12.57											64.11	64.11
Kishanganga (C/S)	4*100	12.57												50.28
THERMAL			210											
Panipat IV	1*210	100.00						210						
Hissar	2*250	100.00							250	250				
Rihand (C/S)	2*500	6.50						32.5	32.5					
NCTPP	4*210	10.00				21	42	21						
Yamunanagar (C/S)	2*210	41.43							174					
Birsingar Lignite (C/S)	2*210	5.71						12	12					
Rihand (C/S)	2*500	6.50								32.5	32.5			
Yamunanagar (C/S)	2*210	41.43								174				

Annexure 5.3.5

Schedule of investments in projects commissioned by HSEB and Central Sector (1988-2000) in 1987-88 price level

Project Name	Total cost (Rs. lakhs)	Expenditure upto 31-3-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000	2000-01
			Schedule of investments in (Rs lakhs)												
HYDRO															
Dadupur	1174.00	0.00	0.00	1 00	10.00	58 70	234 80	352 20	352.20	166.10					
WYC Canal stg 2	2746.00	0 00	570.76	0 00	439 36	549 20	549 20	329 52	219.68	88 28					
Salal (C/S)	1637.17	0.00	6.04	113.52	294.69	409 29	409 29	245 58	158 77						
Chamera (C/S)	4087.90	2086 56	711.08	671 57	586 55	391 03	391 03	58 00							
Dhulhasti (C/S)	11176.70	629.10	1307.70	1406.72	1676 51	2235 34	2011 81	894 14	670 60	344 80					
Tanakpur (C/S)	2938.10	1260.20	387.26	540 12	470 10	235 05	37.10								
Chamera (C/S)	1850.37	3.46	7.19	9.00	148.67	260 17	278 76	408 04	371 67	223 00	146 79				
Tehri (C/S)	16394.30	3431 61	767.66	451 01	655 77	1311 54	1967 32	2623 09	1967.32	1311 54	983 66	819.71	304.06		
Napthajhakri (C/S)	24855.04	203.63	363.53	395 88	994 20	1491 30	2485 50	3728 26	4971 01	3231 15	2485 50	1988 40	1739.05	776.09	
Uri (C/S)	18161.14	86 98	86 10	3130 04	1452 89	2724 17	3632 23	2179 34	1816 11	1452.89	1089 67	509.92			
Sawalkota (C/S)	14051.37	4.15	8.34	13 37	421.54	562 05	843 08	1405 14	2107 71	2810 27	1826 68	1405.14	1124.11	983.60	536.39
Baghiliar (C/S)	11096.04	19.99	24 25	20 82	443 84	776 72	1442 49	1664 41	2441 13	2219 21	1331 53	711 67			
Kolbdam (C/S)	19729 07	0 00	40.71	7 54	591 90	789 19	1381 09	2367 50	2959.48	3551.10	3551 38	1972 99	1570 39	930.24	
Tehri 2 PSS (C/S)	14049.12						561 96	702 46	1026 38	2107 37	2809 82	2809.82	1404 91	1123.93	702.46
Dhauliganga (C/S)	6174.64	3.77	3.45	0 10	0.00	246 99	432 22	802 70	926 20	1358 42	1234.93	740.96	424.90		
Koteshwar (C/S)	9864.94						394 60	690 55	1282 44	1479 74	2170 29	1721.59	1183 79	941.95	
Karcham Wangtoo (C/S)	14797.40						591 90	739 87	1923 66	2219.61	2959 48	2959 48	1479.74	1183.79	739.87
Nibra (C/S)	5918 96								236 76	591.90	887.84	1479.74	1479.74	769.47	473.52
Baspa (C/S)	4833.62								193 39	483 39	725 09	1208 40	1208 40	628.41	386.38
Bursar (C/S)	17416.74						696 67	870 84	2264 18	2612 51	3483 35	3483 35	1741 67	1393.34	870.84
Kishanganga (C/S)	9864.94							394 60	690 55	1282 44	1479 74	2170.29	1972.99	1183.79	690.55
Cap.added in 1888-89	1389.03		1389.03												
Cap.added in 1889-90	1255.60			1255 60											
THERMAL															
Panipat IV	10138 52	0.00	89.28	12 70	1013.05	1620.86	3039 16	3039 16	810.44	505 79					
Hissar	48463.50				553 85	5538 50	8307 75	13846.25	13846 25	1386 25	3323 10	1661.55			
Rihand (C/S)	7198.75			716 69	863 85	1439 75	1799 69	1079.01	719 88	431 93	147.16				
NCTPP	11654.06		1306.52	692.92	2330.97	3263 36	2097 88	932.39	582.74	360 00					
Yamunanagar (C/S)	19274.64				192 74	1927 46	2891.20	4818 66	4818 66	2891 20	1156.48	578 24			
Birsingar Lignite (C/S)	2656.49			29.39	265 65	398 47	664 12	664 12	398 47	159 39	76 87				
Rihand (C/S)	7198.75			0 00	71 99	575.90	863 85	1439 75	1799.69	1079 81	719.88	431.93	215.96		
Yamunanagar (C/S)	19274.64			0 00	0 00	192.74	1927.46	2891.20	4818.66	4818.66	2891 20	1156.48	578.24		
Cap.added in 1888-89	23247.00		23247 00												
GAS TURBINES															
Badri (C/S)	5952 96			11 10	1547 77	2678 83	1190 59	524 67							
Faridabad (C/S)	14280.00			0 00	142.80	3572.00	6429.60	2857 60	1285 92						
Anta (C/S)	3081.92		1301.30	564 04	678 02	462.29	76.19								

Note: In the case of Central sector power projects 'Total cost' is the cost of state's share in the total installed capacity of Central sector projects, and not the total cost of the project

Annexure 5.3.6

Calculation of LRMC of generating capacity for HSEB system (1988-2000) in 1987-88 price level

Year	Investment annuitised		O&M costs		Peak demand (MW)	Discounted stream	
	Hydro (Rs. lakhs)	Thermal	Hydro (Rs. lakhs)	Thermal		Cost (Rs.lakhs)	Increment demand (M
87-88	928.49	0.00	9.28	0.00	1420.00	937.78	
88-89	515.04	3215.87	5.15	78.80	1553.00	3349.24	118.7
89-90	811.47	186.52	8.11	4.66	1696.00	805.77	114.0
90-91	982.32	890.52	9.82	22.26	1850.00	1355.73	109.6
91-92	1444.89	2704.01	14.45	67.60	2025.00	2688.84	111.2
92-93	2200.93	3724.01	22.01	93.11	2218.00	3427.54	109.5
93-94	2453.90	4091.94	24.54	102.30	2430.00	3387.58	107.4
94-95	3285.51	3707.79	32.86	92.69	2666.00	3220.21	106.7
95-96	3303.12	1484.24	33.03	37.11	2907.00	1961.86	97.3
96-97	3259.89	1060.12	32.60	26.50	3177.00	1576.15	97.3
97-98	2877.78	488.09	28.78	12.20	3473.00	1096.92	95.3
98-99	1853.12	101.26	18.53	2.53	3795.00	567.89	92.[illegible]
99-2000	1180.81	0.00	11.91	0.00	4149.00	308.71	90.8
2000-01	528.03	0.00	5.28	0.00	0.00	122.22	
Total						24806.44	1250.6

LRMC of generating capacity (financial) = Total discounted cost / Total discounted demand

= 24806.44/1250.68

= Rs. 1983.11 per kW per year.

LRMC of generating capacity (economic) = 80 % of above

= Rs. 1586.48 per kW per year.

Annexure 5.3.7

Calculation of LRMC of transmission and distribution for HSEB system (1988-2000) in 1987-88 price level

Year	Investment in		Investment annuitised		Peak demand (MW)	Discounted stream		
	EHT & HT (Rs. lakhs)	LT	EHT & HT (Rs. lakhs)	LT		EHT & HT (Rs. lakhs)	LT	Incremental demand(MW)
87-88					1420.00			
88-89	1588.10	2830.64	202.48	360.91	1553.00	180.79	322.24	118.75
89-90	454.26	848.59	57.92	108.19	1696.00	46.17	86.25	114.00
90-91	2393.65	3495.00	305.19	445.61	1850.00	217.23	317.18	109.61
91-92	1997.39	4194.00	254.67	534.74	2025.00	161.85	339.83	111.22
92-93	2111.16	4660.00	269.17	594.15	2218.00	152.74	337.14	109.51
93-94	2875.88	5126.00	366.67	653.57	2430.00	185.77	331.12	107.41
94-95	3118.24	5825.00	397.58	742.69	2666.00	179.84	335.95	106.75
95-96	6180.62	9024.41	788.03	1150.61	2907.00	318.27	464.71	97.34
96-97	2131.46	4475.52	271.76	570.63	3177.00	98.00	205.77	97.36
97-98	1136.28	2508.13	144.88	319.79	3473.00	46.65	102.96	95.30
98-99	888.71	1584.04	113.31	201.97	3795.00	32.57	58.06	92.57
99-2000	548.06	1023.80	69.88	130.53	4149.00	17.94	33.50	90.86
Total						1637.82	2934.71	1250.69

LRMC of EHT & HT (financial) = 1637.82/1250.69

= 130.95 per kW per year

(economic) = 80 % of above

= 104.76 per kW per year

LRMC of LT (financial) = 2934.72/(1250.69*.76)

= 308.75 per kW per year

(economic) = 80 % of above

= 247.00 per kW per year

Note: 1. It has been assumed that EHT&HT handle 100 percent and LT handles 76 percent of the simultaneous system peak .

Annexure 5.3.8

Schedule of capacity addition by GEB and Central sector (1988-2000)

Project name	Total Capacity (MW)	GEB's share (%)	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
HYDRO														
Kadana U1	1*60	100.00		60										
Kadana U2,3	2*60	100.00						120						
Panam Canal	2*1	100.00						2						
Dharoi	2.6	100.00						2.6						
Damanganga	1*1	100.00						1						
THERMAL														
Gandhinagar U3	1*210	100.00		210										
Kutch Lignite U1,2	2*70	100.00		70	70									
Gandhinagar U4	1*210	100.00				210								
Sikka U3	1*120	100.00					120							
Kutch Lignite U4	1*70	100.00					70							
Sikka extn.	2*210	100.00								210	210			
Coastal TPS (C/S)	4*500	50.00										500	500	
Vindhayachal (C/S)	6*210	6.20			78									
Rand (C/S)	2*210	50.00									210			
Vindhayachal extn.	2*500	6.20							62					
GIPCO									145					
NTPC			151	152										
GAS TURBINES														
Utran	3*30+1*45	100.00					90	45						
Pipavav	4*119+2*137	100.00										476	274	
Vatva	2*33.5+1*35	100.00				67	35							
Kawas (c/s)	4*100+2*100	29.50					177							
Gandhar CCGT	6*100	100.00					90	90						

Annexure 5.3.9

Schedule of investments in projects commissioned by GEB and Central Sector (1988-2000) in 1987-88 price level

Project Name	Total cost (Rs. lakhs)	Expenditure upto 31-3-88	Schedule of investments in (Rs. lakhs) 88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
HYDRO														
Khadana	23545.20		1177.26	2354.52	5886.30	7063.56	4709.04	2354.52						
Panama Canal	400.00				20.00	100.00	200.00	80.00						
Dharoi	520.00				26.00	130.00	260.00	104.00						
Damanganga	200.00				10.00	50.00	100.00	40.00						
Cap. added in 1989-90	9418.08			9418.08										
THERMAL														
Kutch Lignite U1,2	19208.76	14585.84	2889.32	1155.73	577.86									
Gandhinagar U4	21852.00	4933.63	6992.64	6992.64	1748.16	1092.60	92.33							
Sikka U3	11285.71	672.57	1128.57	1805.71	3385.71	3385.71	907.43							
Kutch Lignite U4	9358.11		935.81	1684.46	2994.60	2807.43	935.81							
Sikka extn.	46523.40					4652.34	6978.51	11630.85	11630.85	6978.51	2791.40	1860.94		
Coastal TPS (C/S)	110770.00					1107.70	8861.60	13292.40	22154.00	27692.50	16615.50	11077.00	9969.30	
Vindhayachal (C/S)	9404.36	6063.19	1692.79	940.44	470.22	237.74								
Nand (C/S)	23261.70						2326.17	3489.26	5815.43	5815.43	3489.26	1395.70	930.47	
Vindhayachal extn.	6856.66		68.57	548.53	822.80	1371.33	1714.17	1028.50	685.67	411.40	205.70			
GIPCO	16061.65			160.62	1606.17	2569.86	4818.50	4818.50	1284.93	803.08				
Cap. added in 1988-89	25813.37		25813.37											
Cap. added in 1989-90	25486.90			25486.90										
GAS TURBINES														
Utran	12690.00			1269.00	8248.50	2538.00	634.50							
Pipavav	70500.00							705.00	17625.00	31725.00	14100.00	6345.00		
Vatwa	9588.00		958.80	6232.20	1917.60	479.40								
Kawas (c/s)	16346.12	585.53	3940.15	7092.26	3152.12	1576.06								
Gandhar CCGT	56400.00		564.00	14100.00	25380.00	11280.00	5076.00							

Note: In the case of Central sector power projects "Total cost" is the cost of state's share in the total installed capacity of Central sector projects, and not the total cost of the project.

Annexure 5.3.10

Calculation of LRMC of generating capacity for GEB system (1988-2000) in 1987-88 price level

Year	Investment annuitised Hydro (Rs. lakhs)	Investment annuitised Thermal (Rs. lakhs)	O&M costs Hydro (Rs. lakhs)	O&M costs Thermal (Rs. lakhs)	Peak demand (MW)	Discounted stream Cost (Rs.lakhs)	Discounted stream Incremental demand (MW)
87-88					3097		
88-89	0.00	5554.80	0.00	138.87	3275	5083.62	158.93
89-90	1553.98	7556.85	15.54	188.92	3515	7426.09	191.33
90-91	282.54	5352.65	2.83	133.82	3773	4108.28	183.64
91-92	713.08	6413.73	7.13	160.34	4049	4635.64	175.40
92-93	881.23	4220.02	8.81	105.50	4348	2959.45	169.66
93-94	632.28	4123.99	6.32	103.10	4670	2465.11	163.14
94-95	309.42	4457.97	3.09	111.45	5018	2208.34	157.42
95-96	0.00	7547.47	0.00	188.69	5379	3124.51	145.80
96-97	0.00	9361.80	0.00	234.05	5766	3460.36	139.56
97-98	0.00	4743.24	0.00	118.58	6181	1565.38	133.62
98-99	0.00	2636.53	0.00	65.91	6626	776.89	127.93
99-2000	0.00	1389.72	0.00	34.74	7104	365.62	122.69
Total						38179.29	1869.11

LRMC of generating capacity (financial) = Total discounted cost / Total discounted demand

= 39179.29/1869.11

= Rs. 2042.65 per kW per year.

LRMC of generating capacity (economic) = 80 % of above

= Rs. 1634.12 per kW per year.

Annexure 5.3.11

Calculation of LRMC of transmission and distribution for GEB system (1988-2000) in 1987-88 price level

Year	Investment in		Investment annuitised		Peak demand (MW)	Discounted stream		
	EHT & HT (Rs. lakhs)	LT	EHT & HT (Rs. lakhs)	LT		EHT & HT (Rs. lakhs)	LT	Incremental demand(MW)
87-88					3097			
88-89	15391.83	6395.94	1962.46	815.48	3275	1752.19	728.11	158.93
89-90	13679.20	12070.84	1744.10	1539.03	3515	1390.38	1221.82	191.33
90-91	8409.91	3765.00	1072.26	480.04	3773	763.22	341.68	183.64
91-92	10173.86	4518.00	1297.17	576.05	4049	824.37	366.09	175.40
92-93	13028.05	5020.00	1661.08	640.45	4348	942.54	363.18	169.66
93-94	13288.70	5522.00	1694.31	704.46	4670	858.39	356.70	163.14
94-95	7111.10	6275.00	906.67	800.06	5018	410.13	361.91	157.42
95-96	11228.59	5026.88	1431.65	640.93	5379	578.22	258.86	145.80
96-97	13281.38	5897.99	1693.38	751.99	5766	610.65	271.18	139.56
97-98	11984.34	4617.84	1528.00	588.77	6181	491.98	189.57	133.62
98-99	7305.57	3035.77	931.46	387.06	6626	267.77	111.27	127.93
99-2000	2064.55	1821.80	263.23	232.28	7104	67.56	59.62	122.69
Total						8957.40	4629.99	1869.11

LRMC of EHT & HT (financial) = 8957.40/1869.11

= 479.24 per kW per year

(economic) = 80 % of above

= 383.39 per kW per year

LRMC of LT (financial) = 4629.99/(1869.11*.59)

= 419.85 per kW per year

(economic) = 80 % of above

= 335.88 per kW per year

Note: 1. It has been assumed that EHT & HT handle 100 percent and LT handles 59 percent of the simultaneous system peak

Project Name	Total capacity (MW)	MSEB's share (%)	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
			Schedule of capacity addition											
HYDRO														
Bhandadra	1*35	100.00					35							
Ujjani	1*12	100.00				12								
Manikdoh	1*6	100.00					6							
Kanher	1*4	100.00			4									
Surya	1*6	100.00				6								
Dimbhe	1*5	100.00					5							
Warna	2*8	100.00					16							
Koyna stg 4	4*250	100.00							1000					
Dudhganga	2*12	100.00					24							
Surya RBC	1*.75	100.00				0.75								
Mazelgaon	3*.75	100.00					2.25							
Karjanwar	1*3	100.00					3							
~~Bhoa~~	~~1*2~~	~~100.00~~		2										
~~Khadakwasla~~	~~2*8~~	100.00		16										
~~Pawana~~	1*10	100.00	10											
~~Basta 2~~	~~1*15~~	100.00		15										
Ghatghar	2*125	100.00										250		
Ajanta	3*100	100.00										300		
Chicklada	4*100	100.00											200	200
Sordarsarover	6*200+5*50	100.00					130.66	130.66	130.66					
THERMAL														
Chandrapur U5,6	2*500	100.00			500	500								
Chandrapur U7	1*500	100.00								500				
Khaperkhera	2*210	100.00	210	210										
BSES	1*500	100.00							500					
~~Trombay U5~~	1*500	100.00		500										
Ujjani/Bhusawal	2*500	100.00												1000
Parli U6,7	2*210	100.00									210	210		
Khaperkhera U3,4	2*210	100.00					210	210						
Chandrapur (C/S)	2*500	42.53								212.6	212.6			
~~Korba (C/S)~~	2*500+1*500	32.54		162.7										
~~Vindhyachal~~ (C/S)	6*210+2*500	32.54	137	68	68									
GAS TURBINES														
Uran	3*120	100.00					120	260						
Dhabol	4*120+2*140	100.00				760								
Kawas	4*111+2*103	32.54												

Annexure 5.3.13

Schedule of investments in projects commissioned by MSEB and Central Sector (1988-2000) in 1987-88 price level

Project Name	Total cost (Rs.lakhs)	Expenditure upto 31-3-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000	2000-01	2001-02	2002-03
HYDRO																	
Bhandardra	2835.00	673.00	563.40	501.01	510.30	283.50	226.80	76.91									
Ujjani	2672.00	750.00	1277.00	232.00	213.76	160.32	38.92										
Manikdoh	620.00	167.00	155.75	40.00	124.00	62.00	49.60	21.65									
Kanher	546.00	103.00	131.86	116.00	109.20	85.94											
Surya	707.00	243.00	102.65	82.40	141.40	84.84	52.71										
Dimbhe	546.00	154.00	123.89	28.80	109.20	54.60	43.60	39.83									
Warna	1680.00	488.00	424.78	221.60	168.00	134.40	117.60	125.62									
Koyna stg 4	37640.00	504.00	497.35	649.60	3764.00	5646.00	9410.00	9410.00	4893.20	2865.85							
Dudhganga	2436.00	1000.00	466.37	230.40	243.60	194.88	170.52	130.23									
Surya RBC	1490.45	0.00	1.77	16.00	372.61	745.23	354.84										
Hazelgaon	571.35	0.00	0.00	0.00	28.57	142.84	285.68	114.27									
Karjowar	761.80				38.09	190.45	380.90	152.36									
Dhoo	308.80	59.00	136.20	103.20	10.40												
Khadakwasla	2076.50	1237.00	253.90	372.80	212.80												
Pawana	1398.94	1244.00	97.34	57.60	0.00												
Dasta 2	1256.54	695.00	174.34	284.00	103.20												
Ghatghar	23106.00					924.24	1617.42	3003.78	3465.90	5083.32	4621.20	2772.72	1617.42				
Ajanta	41884.00	0.00	0.00	0.00		1675.36	2931.88	5444.92	6282.60	9214.40	8376.80	5026.08	2931.88				
Chicklada	60177.00	0.00	0.00	0.00			2407.08	4212.39	7823.01	9026.55	13238.94	12035.40	7221.24	4212.39			
Sardarsarover	36801.00	3573.00	546.90	1795.20	5520.15	9200.25	9200.25	4784.13	2181.12								
THERMAL																	
Chandrapur U5,6	110770.00	14487.00	6517.86	9734.51	33231.00	22154.00	13292.40	6646.20	4707.03								
Chandrapur U7	55385.00	0.00	0.00	0.00	553.85	4430.80	6646.20	13846.25	13846.25	8307.75	5538.50	2215.40					
Khaperkhera	53571.42	24775.00	11250.00	11150.44	6395.98												
BSES	55385.00	0.00	0.00	553.85	4430.80	6646.20	13846.25	13846.25	8307.75	5538.50	2215.40						
Trombay U5	55385.00	12320.00	19304.75	13846.25	5538.50	4295.50											
Ujjani/Bhusawal	110770.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1107.70	8861.60	13292.40	22154.00	27692.50	16615.50	11077.00	6646.2	3323.1
Parli U6,7	46523.40	0.00	0.00	0.00	0.00	0.00	465.23	4652.34	6978.51	11630.85	11630.85	6978.51	2791.40	1395.70			
Khaperkhera U3,4	45442.00	0.00	454.42	4544.20	6816.30	11360.50	11360.50	6816.30	2726.52	1363.26							
Chandrapur (C/S)	49696	242.05	0.00	0.00	0.00	470.99	3767.92	5651.88	11774.75	11774.75	7064.85	4709.90	2825.94	1412.97			
Korba (C/S)	54066.00	10343.00	10923.30	13516.70	5406.60	3244.01	2633.01										
Vindhyachal (C/S)	81460.60	2123.00	814.61	6516.05	9775.27	16292.12	20365.15	12219.09	8146.06	4073.03	1135.42						
GAS TURBINES																	
Uran	31950.00	0.00	0.00	319.50	7987.50	14377.50	6390.00	2875.50									
Dhabol	71440.00	0.00	714.40	17860.00	32148.00	14288.00	6429.60										
Kawas (C/S)	17384.70	477.70	3476.94	7823.12	3476.94	1043.08	1086.94										

Note: In the case of Central sector power projects 'Total cost' is the cost of state's share in the total installed capacity of Central sector projects, and not the total cost of the project

Annexure 5.3.14

Calculation of LRMC of generating capacity for MSEB system (1988-2000) in 1987-88 price level

Year	Investment annuitised		O&M costs		Peak demand (MW)	Discounted stream	
	Hydro (Rs. lakhs)	Thermal	Hydro (Rs. lakhs)	Thermal		Cost (Rs.lakhs)	Increme demand
87-88	1306.80	8257.90	13.07	206.45	5411	9784.22	
88-89	594.45	7845.89	5.94	196.15	5905	7716.45	4
89-90	566.71	10947.84	5.67	273.70	6394	9402.04	38
90-91	1400.31	14759.50	14.00	368.99	6870	11774.84	33
91-92	2350.18	12571.84	23.50	314.30	7525	9697.89	41
92-93	3274.55	11001.10	32.75	275.03	8073	8275.02	31
93-94	3301.93	8485.61	33.02	212.14	8628	6096.14	28
94-95	2957.50	7343.31	29.57	183.58	9335	4755.98	31
95-96	3142.82	6572.59	31.43	164.31	10116	4002.95	31
96-97	3148.43	5211.78	31.48	130.29	10961	3073.15	30
97-98	2380.10	4597.37	23.80	114.93	11878	2291.23	29
98-99	1412.46	4247.01	14.12	106.18	12871	1661.55	28
99-2000	505.49	2476.58	5.05	61.91	13947	782.61	27
2000-01	0.00	1412.32			0.00	323.67	
2001-02	0.00	847.39			0.00	173.39	
2002-03	0.00	423.68			0.00	77.41	
Total						79888.54	397

LRMC of generating capacity (financial) = Total discounted cost / Total discounted demand

= 79888.54/3974.96

= Rs. 2009.80 per kW per year.

LRMC of generating capacity (economic) = 80 % of above

= Rs. 1607.84 per kW per year.

Annexure 5.3.15

Calculation of LRMC of transmission and distribution for MSEB system (1988-2000) in 1987-88 price level

Year	Investment in: EHT & HT (Rs. lakhs)	Investment in: LT (Rs. lakhs)	Investment annuitised: EHT & HT (Rs. lakhs)	Investment annuitised: LT (Rs. lakhs)	Peak demand (MW)	Discounted stream: EHT & HT (Rs. lakhs)	Discounted stream: LT (Rs. lakhs)	Discounted stream: Incremental demand (MW)
87-88					5411			
88-89	14480.11	7121.86	1846.21	908.04	5905	1648.41	810.75	441.07
89-90	14140.49	12612.21	1802.91	1608.06	6394	1437.27	1281.93	389.83
90-91	27216.95	6870.00	3470.16	875.93	6870	2469.99	623.47	338.81
91-92	36098.85	8244.00	4602.60	1051.11	7525	2925.04	668.00	416.26
92-93	23238.51	9160.00	2962.91	1167.90	8073	1681.23	662.70	3[illegible]0.95
93-94	20486.40	10076.00	2612.02	1284.69	8628	1323.33	650.86	281.18
94-95	12837.45	11450.00	1636.78	1459.88	9335	740.39	660.37	319.81
95-96	16603.96	4191.11	2117.00	534.37	10116	855.02	215.82	315.43
96-97	20499.21	4681.46	2613.65	596.89	10961	942.51	215.24	304.72
97-98	11436.43	4507.94	1458.14	574.76	11878	469.48	185.06	295.25
98-99	9817.54	4828.64	1251.74	615.65	12871	359.84	176.99	285.46
99-2000	3689.59	3290.82	470.42	419.58	13947	120.75	107.70	276.18
Total						14973.26	6258.89	3974.96

LRMC of EHT & HT (financial) = 14973.27/3974.96

= 376.69 per kW per year

(economic) = 80 % of above

= 301.35 per kW per year

LRMC of LT (financial) = 6258.89/(3974.96*.54)

= 291.59 per kW per year

(economic) = 80 % of above

= 233.27 per kW per year

Note: 1. It has been assumed that EHT & HT handle 100 percent and LT handles 54 percent of the simultaneous system peak

Annexure 5.3.16

Schedule of capacity addition by MPEB and Central sector (1988-2000)

Project Name	Total Capacity (MW)	MPEB's share (%)	Schedule of capacity addition 88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
HYDRO														
Birsingpur	1*20	100.00			20									
Hasdeo-Bango.	3*40	100.00					120							
Bansagar	3*105+2*15	100.00				345								
Tawa LBC	4*3	100.00				12								
Bhingbar	4*.6	100.00					2.4							
Barna	2*.75	100.00					1.5							
Narmadasagar	8*125	100.00										250	375	375
Rajghat (50%)	3*15	50.00								22.5				
Chitrakoot	2*40	100.00											80	
Omkareshwar	8*65	100.00											260	260
Maheshwar	10*40	100.00											200	200
Cap.addition (1988-89)	90	100.00	90											
Cap.addition (1989-90)	.4	100.00		0.4										
THERMAL														
Birsingpur U3,4	2*210	100.00				420								
Birsingpur extn.	2*210	100.00						210	210					
Korba West	2*210	100.00							420					
Amarkantak	1*120	100.00								120				
Nand (50%)	2*210	50.00												
Bandhav stg 1.	2*500	100.00								500	500			
Cap.addition (1988-89)	119	100.00	119											

Annexure 5.3.17

Schedule of investments in projects commissioned by MPEB and Central Sector (1988-2000) in 1987-88 price level

Project Name	Total cost (Rs. lakhs)		Expenditure upto 31-3-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000	2000-01
				Schedule of investments in (Rs. lakhs)												
HYDRO																
Birsingpur	1931.00	1931	87.00	459.30	464.00	579.30	289.65	51.75								
Hasdeo Bango	7562.00	7562	1688.00	673.45	767.20	1663.64	1512.40	907.44	349.87							
Bansagar	81397.00	81397	21534.00	5561.95	4380.80	24419.10	16279.40	8139.70	1082.05							
Tawa LBC	1440.00	1440			72.00	360.00	720.00	288.00								
Bhinghar	434.00	434				21.70	108.50	217.00	86.80							
Barna	215.70	215.7				10.79	53.93	107.85	43.14							
Narmadasagar	105310.00	105310	5146.00	2076.11	3431.20	2106.20	4212.40	4212.40	10531.00	14743.40	18955.80	14743.40	10531.00	8424.80	4212.40	1983.89
Rajghat (50%)	1350.00	1350					67.50	135.00	337.50	405.00	270.00	135.00				
Chitrakoot	12035.00	12035					481.40	601.75	1564.55	1805.25	2407.00	2407.00	1203.50	962.80	601.75	
Omkareshwar	38761.00	38761					1162.83	1550.44	2713.27	4651.32	5814.15	6976.98	6976.98	3876.10	3100.88	1938.05
Maheshwar	27876.10	27876.1		442.48	20.40		836.28	1115.04	1951.33	3345.13	4181.42	5017.70	5017.70	2787.61	2230.09	930.93
Cap.addition (1988-89)	17658.90	17658.9		17658.90												
Cap.addition (1989-90)	80.00	80			80.00											
THERMAL																
Birsingpur U3,4	44017.86			892.86	6602.68	13205.36	13205.36	6602.68	2641.07	867.85						
Birsingpur extn.	44017.86					4401.79	6602.68	11004.47	11004.47	6602.68	2641.07	1760.71				
Korba West	46523.40					465.23	4652.34	6978.51	11630.85	11630.85	6978.51	2791.40	1395.70			
Amarkantak	17767.86						177.68	1776.79	2842.86	5330.36	5330.36	1421.43	888.39			
Hand (50%)	23261.72								232.62	2326.17	3489.26	5815.43	5815.43	3489.26	1395.70	697.85
Bandhav stg 1.	153570.00					1535.70	12285.60	18428.40	30714.00	38392.50	23035.50	15357.00	9214.20	4607.10		
Cap.addition (1988-89)	13181.63			13181.63												
Cap.addition (1989-90)	0.00				0.00											

Note: In the case of Central sector power projects 'Total cost' is the cost of state's share in the total installed capacity of Central sector projects, and not the total cost of the project.

Annexure 5.3.18

Calculation of LRMC of generating capacity for MPEB system (1988-2000)[1] in 1987-88 price level

Year	Investment annuitised		O&M costs		Peak demand (MW)	Discounted stream	
	Hydro (Rs. lakhs)	Thermal	Hydro (Rs. lakhs)	Thermal		Cost (Rs.lakhs)	Incremen demand (
87-88	3414.60	0.00	34.15	0.00	2095	3448.75	
88-89	3224.66	1794.50	32.25	44.86	2416	4550.24	208.
89-90	1105.87	841.84	11.06	21.05	2649	1578.30	181.
90-91	3499.29	2500.03	34.99	62.50	2877	4339.59	200.
91-92	3086.91	4707.77	30.87	117.69	3158	5048.08	219.
92-93	2079.16	5710.83	20.79	142.77	3503	4513.06	216.
93-94	2239.14	7530.90	22.39	188.27	3884	5056.53	216.
94-95	2994.01	8306.68	29.94	207.67	4311	5219.34	217.
95-96	3795.40	5288.02	37.95	132.20	4792	3737.37	185.
96-97	3513.61	3461.11	35.14	86.53	5251	2559.03	182.
97-98	2847.50	2207.50	28.48	55.19	5756	1654.51	178.
98-99	1926.16	1032.29	19.26	25.81	6310	863.44	173
99-2000	1217.41	177.95	12.17	4.45	6915	362.42	170.
2000-01	582.34	88.89	0.00		7578	153.85	
Total						43084.51	2349.

LRMC of generating capacity (financial) = $\frac{\text{Total discounted cost}}{\text{Total discounted demand}}$

= 43084.51/2349.12

= Rs. 1834.07 per kW per year.

LRMC of generating capacity (economic) = 80 % of above

= Rs. 1467.25 per kW per year.

Annexure 5.3.19

Calculation of LRMC of transmission and distribution for MPEB system (1988-2000) in 1987-88 price level

Year	Investment in		Investment annuitised		Peak demand (MW)	Discounted stream		
	EHT & HT (Rs. lakhs)	LT	EHT & HT (Rs. lakhs)	LT		EHT & HT (Rs. lakhs)	LT	Incremental demand(MW)
87-88					2095			
88-89	7539.71	7845.38	961.31	1000.29	2416	858.31	893.11	208.04
89-90	2027.48	2970.67	258.50	378.76	2649	206.08	301.95	181.76
90-91	8927.48	10155.00	1138.25	1294.76	2877	810.19	921.59	200.01
91-92	16566.68	12186.00	2112.25	1553.72	3158	1342.37	987.41	219.25
92-93	18527.01	13540.00	2362.19	1726.35	3503	1340.37	979.58	216.19
93-94	14311.94	14894.00	1824.77	1898.99	3884	924.49	962.08	216.33
94-95	11548.47	16925.00	1472.43	2157.94	4311	666.05	976.14	217.58
95-96	13382.04	15222.06	1706.21	1940.81	4792	689.11	783.86	185.38
96-97	14921.36	10975.74	1902.47	1399.41	5251	686.05	504.64	182.11
97-98	12241.41	8946.33	1560.78	1140.66	5756	502.53	367.26	178.37
98-99	4446.42	4626.69	566.92	589.90	6310	162.98	169.58	173.92
99-2000	1479.22	2167.37	188.60	276.34	6915	48.41	70.93	170.18
Total						8236.94	7918.13	2349.12

LRMC of EHT & HT (financial) = 8236.94/2349.12

= 350.64 per kW per year

(economic) = 80 % of above

= 281.31 per kW per year

LRMC of LT (financial) = 7918.13/(2349.12*.42)

= 802.54 per kW per year

(economic) = 80 % of above

= 642.03 per kW per year

Note: 1. It has been assumed that EHT & HT handle 100 percent and LT handles 42 percent of the simultaneous system peak

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Project Name	Total Capacity (MW)	TNEB's share (%)	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
			Schedule of capacity addition											
HYDRO														
Kadamparai PSS *	4*100	100.00	100											
Lower Mettur HEP	8*15	100.00	30											
Pykara	1*2	100.00		2										
Lower Bhavani	4*2	100.00		8										
Vaigai Micro Hydel	2*3	100.00		6										
Pykara Ultimate	3*50	100.00								150				
Sathanur HES	2*7.5	100.00							15					
Lower Bhavani R.B.C	2*4	100.00							8					
Paralayar	1*25	100.00										25		
Heller PSSR **	9*300	100.00												300
Kundah V extn.	1*30	100.00										30		
B.K Barrage	1*90	100.00										90		
THERMAL														
Tuticorin Stg. III	2*210	100.00			210	210								
Mettur Stg. II	2*210	100.00	210	210										
North Madras I&II	5*210	100.00					420	210						
North Madras III	2*500	100.00										500	500	
Cuddalore	3*210	100.00											500	500
Neyveli III M.C	3*500	100.00										500	500	500
Neyveli I M.C extn.	2*210	100.00									210	210		
Neyveli II M.C	1*210	100.00									210			
Manglore (C/S)	2*210	22.50							47.25	47.25				
Kayamkulam (C/S)	2*210	22.50							47.25	47.25				
Manguru SIPS	2*500	22.50								112.5	112.5			
Kayamkulam extn.(C/S)	2*500	22.50									112.5	112.5		
Manglore extn. (C/S)	2*500	22.50										112.5	112.5	
Pondicherry (C/S)	2*500	22.50											112.5	112.5
GAS TURBINES														
Kovilkalapal	1*5			5										
Bhuvanagiri	1*3		3											
Basin Bridge	4*30						120							

Note: * 3*100 MW has already been installed before 1988-89
** only 300 MW is proposed to be installed in IX plan

Annexure 5.3.21

Schedule of investments in projects commissioned by TNEB and Central Sector (1988-2000) in 1987-88 price level

Project Name	Total cost (Rs. lakhs)	Expenditure upto 31-3-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000	2000-01	2001-02	2002-03
			Schedule of investments in (Rs lakhs)														
HYDRO																	
Pykara	615.71	435.71	180.00	-													
Lower Mettur HEP	16538.00	15534	733	250	21												
Pykara	615.71	435.71	86.2	61.57	24.63	7.6											
Lower Bhavani	2012.86	1524.29	457.14	31.43													
Vaigai Micro Hydel	1335.71	972.86	342.85	20.00													
Pykara Ultimate	10624.29		285.71	517.14	1034.29	2067.14	3101.43	1551.43	1037.14	1032.86							
Sathanur HES	2301.43		142.86	151.43	172.86	431.43	647.14	324.29	215.71	215.71							
Lower Bhavani R.B.C	1620.00		142.86	147.14	147.14	224.29	442.86	221.43	147.14	147.14							
Paralayar	2063						82.52	206.31	309.47	515.77	515.77	260.2	165.05				
Neller PSSR **	58863.26					1765.89	2354.52	4120.41	7063.56	8829.45	10595.34	10595.34	5886.3	4709.3	2943.15		
Kundah V extn.	4152.00						166.00	415.2	622.8	1038	1038	539.76	332.16				
P.K Barrage	17658.91					706.36	1236.12	2295.66	2648.84	3884.96	3531.78	2119.07	1236.12				
THERMAL																	
Tuticorin Stg. III	62779.00	8274	8030	10000	18033.7	12555.8	3138.95	1946.55									
Mettur Stg. II	38654.95	22536.26	12087.91	3481.32	549.45												
North Madras I&II	72110.00	3203.00	696.00	5000.00	10013.80	10032.00	10032.00	10013.80	4325.52	1193.00							
North Madras III	120879.12						1107.7	8861.60	13292.40	22154.00	27692.50	16615.50	11077.00	6646.20	3323.1		
Cuddalore	143020.88							1107.70	8861.60	13292.40	22154.00	27692.50	16615.50	11077.00	6646.2	3323.1	
Neyvali III M.C	166155.16						1661.55	13292.4	19938.6	33231	41538.75	24923.25	16615.50	9969.30	4984.65		
Neyvali I M.C extn.	43532.00						465.21	1652.3	6987.45	11630.75	11630.75	6978.45	2791.38	1395.69			
Neyvali II M.C	23261.51						232.62	2326.17	3721.87	6978.51	6978.51	1860.74	1163.09				
Manglore (C/S)	10467.78					104.68	1046.78	1570.17	2616.94	2616.94	1570.17	628.07	314.03				
Kayankulam (C/S)	10467.78					104.68	1046.78	1570.17	2616.94	2616.94	1570.17	628.07	314.03				
Nanguru STPS	24923.26					249.23	1993.86	2990.79	4984.65	6230.81	3738.49	2492.33	1495.4	747.7			
Kayankulam extn.(C/S)	24923.26						249.23	1993.86	2990.79	4984.65	6230.81	3738.49	2492.33	1495.4	747.7		
Manglore extn. (C/S)	24923.26							249.23	1993.86	2990.79	4984.65	6230.81	3738.49	2492.33	1495.4	747.7	
Pondicherry (C/S)	24923.26								249.23	1993.86	2990.79	4984.65	6230.81	3738.49	2492.33	1495.4	747.7
GAS TURBINES																	
Kovilkalapal	682.86	71.43	611.43														
Bhuvanagiri	704.29		500.00	204.29													
Basin Bridge	9065.71				1321.43	4532.86	2267.14	944.20									

inexure 5.3.22

Calculation of LRMC of generating capacity for TNEB system (1988-2000) in 1987-88 price level

Year	Investment annuitised		O&M costs		Peak demand (MW)	Discounted stream	
	Hydro (Rs. crores)	Thermal	Hydro (Rs. crores)	Thermal		Cost (Rs. crs)	Incremer demand (
37-88	4270.54	4345.80	42.71	108.65	3382	8767.69	
88-89	288.81	2712.24	2.89	67.81	3670	2688.53	257.
89-90	144.02	2434.82	1.44	60.87	3954	2105.51	226.
90-91	160.60	4103.41	1.61	102.59	4253	3109.20	212.
91-92	305.83	5034.15	3.06	125.85	4615	3475.58	230.
92-93	487.05	4496.98	4.87	112.42	4928	2894.62	177.
93-94	771.71	7568.23	7.72	189.21	5361	4325.04	219.
94-95	778.83	10015.44	7.79	250.39	5792	4999.56	194.
95-96	851.49	13969.62	8.51	349.24	6291	6130.49	201.
96-97	678.51	16408.86	6.79	410.22	6794	6312.25	181.
97-98	351.24	11813.61	3.51	295.34	7337	4012.98	174.
98-99	208.00	7233.89	2.08	180.85	7924	2191.95	168.
9-2000		4312.51	0.00	107.81	8558	1134.59	162.
000-01		2192.62				502.49	
001-02		519.03				106.20	
Total						52756.68	2407

LRMC of generating capacity (financial) = $\frac{\text{Total discounted cost}}{\text{Total discounted demand}}$

= 52756.68/2407.60

= Rs. 2191.26 per kW per year.

LRMC of generating capacity (economic) = 80 % of above

= Rs. 1753.00 per kW per year.

Annexure 5.3.23

Calculation of LRMC of transmission and distribution for TNEB system (1988-2000) in 1987-88 price level

Year	Investment in		Investment annuitised		Peak demand (MW)	Discounted stream		
	EHT & HT (Rs. lakhs)	LT	EHT & HT (Rs. lakhs)	LT		EHT & HT (Rs. lakhs)	LT	Incremental demand(MW)
87-88					3382			
88-89	3210.93	5387.04	409.39	686.85	3670	365.53	613.26	257.14
89-90	1778.11	4146.82	226.71	528.72	3954	180.73	421.49	226.40
90-91	3045.87	10425.00	388.35	1329.19	4253	276.42	946.09	212.82
91-92	5294.04	12510.00	674.99	1595.03	4615	428.97	1013.67	230.06
92-93	6547.21	13900.00	834.77	1772.25	4928	473.67	1005.62	177.60
93-94	9113.56	15290.00	1161.98	1949.48	5361	588.69	987.66	219.37
94-95	7450.19	17375.00	949.90	2215.31	5792	429.69	1002.09	194.96
95-96	10600.07	36280.56	1351.51	4625.77	6291	545.85	1868.27	201.54
96-97	16921.84	39986.91	2157.53	5098.33	6794	778.03	1838.51	181.39
97-98	15911.89	33781.59	2028.77	4307.15	7337	653.21	1386.79	174.83
98-99	8099.57	13588.80	1032.70	1732.57	7924	296.88	498.07	168.75
99-2000	2963.13	6910.47	377.80	881.08	8558	96.97	226.15	162.73
						5114.64	11807.67	2407.60

LRMC of EHT & HT (financial) = 5114.64/2407.60

= 212.44 per kW per year

(economic) = 80 % of above

= 169.95 per kW per year

LRMC of LT (financial) = 11807.67/(2407.60*.53)

= 925.35 per kW per year

(economic) = 80 % of above

= 740.28 per kW per year

Note: 1. It has been assumed that EHT & HT handle 100 percent and LT handles 53 percent of the simultaneous system peak